TOTAL

1980 Annual Report Total Petroleum (North America) Ltd.

Company Profile

Total Petroleum (North America) Ltd.
- Areas of Exploration and Production
- Marketing Area
- Principal Offices
- Refineries

Total Petroleum (North America) Ltd. is a growing petroleum company active in exploration and production in Canada and the U.S., and refining and marketing in the mid-continent U.S.

TOTAL's strong land position and long-life reserves are the foundation of its Canadian operations. Production in the U.S. began in the early 1970's and is growing steadily through exploration and acquisitions.

Through expansion and acquisitions, refining capacity has increased to 150,000 barrels per day in three locations, Alma, Michigan; Arkansas City, Kansas; and Ardmore, Oklahoma. Two refineries have been upgraded to produce a high yield of gasoline. Upgrading will soon begin at the recently acquired Ardmore refinery.

Through company-owned service stations and independent distributors, TOTAL markets in 22 mid-continent and Great Lakes states under the brand names TOTAL, BEST, APCO and VICKERS.

TOTAL will continue to expand by reinvesting its cash flow in operations and through selected acquisitions.

Highlights

	1980	1979
OPERATING		
Crude oil production (barrels per day)	**10,427**	10,897
Natural gas sales (thousands of cubic feet per day)	**51,618**	50,384
Proved crude oil reserves (barrels)	**30,731,000**	31,808,000
Proved gas reserves (thousands of cubic feet)	**288,106,000**	274,901,000
Refinery input (barrels per day) (i)	**129,655**	87,202
Refined product sales (barrels per day) (ii)	**162,243**	91,447
FINANCIAL (U.S. Dollars)		
Total revenue	**$1,604,537,000**	$910,505,000
Net income	**47,749,000**	29,871,000
Net income per share	**2.30**	1.82
Funds provided by operations (iii)	**110,681,000**	75,029,000
Capital expenditures (iv)	**66,866,000**	54,262,000
Shareholders' equity	**357,879,000**	306,565,000
Total assets	**1,155,017,000**	624,262,000

(i) Includes Ardmore, Oklahoma refinery's average daily input for three months of 1980.

(ii) Includes Vickers Division's average daily refined product sales for three months of 1980.

(iii) Net income plus income charges not affecting working capital in the year. Refer to Consolidated Statement of Changes in Financial Position for other sources and uses of funds.

(iv) Excludes acquisition of certain assets from Traverse Corporation and Vickers Petroleum Corporation in 1980.

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Calgary, Alberta T2P 0M9
403-265-9080

Principal Executive Office
East Superior Street
Alma, Michigan 48801
517-463-1161
After August 1981
One Denver Place
Denver, Colorado 80211

Investor Relations
70 Pine Street
Suite 3310
New York, New York 10270
212-482-8460

Exploration and Production
2950 One Allen Center
500 Dallas Ave.
Houston, Texas 77002
713-658-0972

Marketing
28001 Citrin Drive
Romulus, Michigan 48174
313-946-5500

Crude Oil and Product Supply
6701 N. Broadway
Oklahoma City, Oklahoma 73116
405-840-2901

Refineries
Alma, Michigan
Arkansas City, Kansas
Ardmore, Oklahoma

ON THE COVER

Installation of the reactor-regenerator unit, a part of the $14 million upgrading program now completed at the Arkansas City refinery. This unit is a major part of the Fluid Catalytic Cracking process which utilizes high temperatures and a catalyst to convert the heavy fractions of crude oil into gasoline, heating oil and other products.

CONTENTS

To Our Shareholders

The largest acquisition investments in the company's history and another record increase of cash flow were the highlights of 1980 for Total Petroleum (North America) Ltd.

These events represent a new culmination of the growth strategy of the past several years, and place the company on a new threshold for its development in the fast-changing world of the 1980's.

The acquisition of Vickers Petroleum Corporation on October 2 for $245 million, plus adjustments and working capital at the closing, increased TOTAL's refining capacity by 70% to about 150,000 barrels per day and nearly doubled our refined product sales. We illustrate, in the Refining and Marketing section of the report, how the blending of Vickers' assets with our existing operations will strengthen our competitive posture in the changing markets of the 1980's.

Earlier in the year, on January 1, we acquired the oil and gas producing properties of Traverse Corporation, for $42 million, which increased our U.S. oil and gas reserves by about 20%.

During the first quarter of 1980, we acquired 6.9% of the shares of Supron Energy Corporation, an oil and gas exploration and production company, in the open market, for $31 million.

Capital expenditures, other than acquisitions, increased to $66.9 million in 1980 from $54.3 million in 1979, with about 70% allocated to exploration and production and 30% to refining and marketing.

TOTAL's cash flow, or "funds provided by operations", topped the $100 million mark in 1980, at $110.7 million versus $75.0 million in 1979; a record year-to-year increase of 47%, following a 45% increase from 1978 to 1979. Net income reached $47.7 million, versus $29.9 million in 1979. Cash flow, which more than doubled over the past two years, is the most important measure of our performance, providing the financial resources for an increasing level of capital expenditure, debt service and the payment of common and preferred dividends.

All segments of our business contributed to increases in cash flow, aided by a favorable trend of prices and margins. In 1980, refining and marketing in the U.S. provided about 60% of cash flow, U.S. production about 25% and Canadian production about 15%.

Over the past several years, TOTAL's strategy of growth has been based upon reinvesting its cash flow, using the leverage of existing and new assets to finance acquisitions, and raising new equity when circumstances were favorable in order to restore flexibility. This cycle has been repeated several times since the acquisition of Hanover Petroleum (1976), followed by Apco (1977-78), Traverse Corporation (1980) and finally Vickers Petroleum (1980). The last two acquisitions were made in the wake of the preferred share issue of late 1979.

Five years ago TOTAL was a regional independent refiner-marketer in Michigan and a medium size explorer and producer in Western Canada, taking its initial steps in exploration-production in the U.S. We have now become a significant factor among the independent refiners and marketers of the mid-continent area with three refineries, in Michigan, Kansas and Oklahoma, and marketing outlets in 22 states. We have become active in several prospective exploration areas of the United States while continuing to enhance our Western Canadian position, in the Elmworth area in particular. Through exploration and acquisitions we have increased our oil and gas production and reserves on an energy equivalent basis, contrary to the generally declining trend of oil and gas reserves in North America.

In summary, we have considerably broadened our base of assets in refining, marketing, production and exploration. This puts us in a position to benefit from favorable market developments such as occurred in 1979 and 1980, and to build further by adapting these assets to meet the trends of the future.

During this period of expansion, we have developed expertise in certain specific areas. In marketing, let us mention self-service and merchandising at the station, with substantial impact on sales volumes and cash flows. In the refining field, we have often referred to the residual fuel upgrading technology applied to the Alma and the Arkansas City refineries, which is largely responsible for our financial performance of the past two years. In exploration, progress in the technology of seismic modeling and interpretation has improved our success ratio, in the Elmworth region in particular. In the production area, we are involved in several enhanced recovery projects.

This overview of TOTAL's strategy of the past several years, and of its results, is not intended to boast our accomplishments but to emphasize the new dimension attained by the company, hence the broader spectrum of opportunities it faces for its future.

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Opportunities are shaped to a large extent by the political, economic and regulatory environment.

In the United States, the complete decontrol of crude oil prices, and the partial and gradual decontrol of natural gas, open up expanded opportunities for exploration and production. In the refining sector, decontrol means the end of multi-tier crude oil prices, hence the end of the ill-fated entitlements program. Elimination of allocation controls also means increased competition for crude oil supplies and a more competitive market for finished products.

The recent National Energy Program of Canada, calling for more price controls, more taxation and more government intervention, is truly an anomaly in the Western world which, for the most part, has finally awakened to the facts of life of energy after the shock of 1979 and has relaxed the constraints on the petroleum industry — notably in the United States. This is one reason why we remain hopeful that a proper balance will eventually be struck between political objectives and economic realities in Canada.

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For 1981, a major objective is to streamline and consolidate our organizational structure in the aftermath of the Vickers acquisition, as well as to reflect our continuing commitment to exploration and

production. The major management functions of the company are currently scattered in various locations as a result of history. We have decided to locate our executive headquarters in Denver, Colorado, in mid-1981. The concentration of the senior management in a major center of the energy industries is a tangible sign of our new dimension and of our determination to broaden our scope. It will facilitate communications and planning, as well as hiring and development of professional and managerial staff. We remain committed, however, to maintaining the lean and aggressive style of management of an independent company so essential to effectively react to opportunities in a competitive and rapidly changing environment.

In 1981 and beyond we will continue to build upon our enlarged asset base, strengthen our competitive position, and seek new opportunities.

- We will upgrade the Ardmore refinery: a $15 million program similar to the Alma and Arkansas City programs is already underway and should be completed in 1982.
- We will endeavor to maintain our competitive position regarding access to domestic and foreign crude oil in a decontrolled environment.
- We will expand the self-service and merchandising concepts, thus improving the competitive position of our company - operated stations and retaining our lead among low-cost marketers.
- We will step up our efforts to generate higher potential exploration prospects in the United States and to increase reserves through enhanced recovery projects.
- We will continue to maintain and upgrade our extensive and highly prospective land position in Western Canada with a view to the future: Elmworth gas will be needed before the long term.

The 1981 capital expenditure program amounts to about $100 million, of which approximately two-thirds is allocated to exploration and production.

Our financial resources will continue to be provided primarily by our cash flow. Cash flow from oil and gas production is assured of continued growth. A possible leveling-off of Canadian production cash flow because of the National Energy Program will be more than offset by the growing share of production cash flow generated in the U.S. Short-term projections of refining and marketing cash flow have always been hazardous because of the cyclical nature of the business. Since the fourth quarter of 1980, a rapid escalation of crude oil costs has occurred, caused by acceleration of decontrol of U.S. domestic crude oil, OPEC price increases, and finally the complete decontrol of domestic crude oil prices in the U.S. in January 1981. Contrary to prior periods of steep crude oil cost increases which were accompanied by supply shortages, there is now an abundant supply of products and continued weak demand. This caused a lag between crude oil cost increases and product price increases that resulted in reduction of refiners' margins in late 1980 and early 1981. Some time will be needed to establish a new equilibrium between the cost of crude oil and the price of finished products. The duration of this adjustment period will determine, in large measure, TOTAL's 1981 results.

But, as always, we remain confident about the long-term cash flow potential of our refining and marketing assets because of our competitive posture, enhanced by the Vickers acquisition, and leveraged by refinery upgrading investments: the Arkansas City project will produce its full effect during most of 1981. The Ardmore project will have an effect on part of 1982 and all of 1983.

In spite of the debt incurred for the Vickers acquisition, we retain substantial borrowing capacity backed by our oil and gas reserves. Given the right opportunity and a sufficient degree of financial flexibility, we remain alert to selected acquisitions, with increased emphasis on exploration and production assets.

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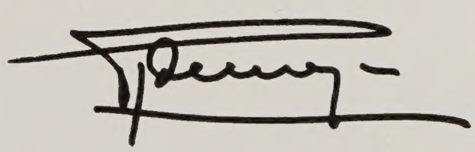
Three of our Directors left our midst in 1980: James W. Glanville, a Director since 1970 and Chairman of the Board since 1973; Andre Jacqmin, a Director since 1973 and President of the company from 1973 until 1975; Armand Guilbaud, a Director since 1979. We express our gratitude to each one of them for their dedicated participation in the company's affairs in their respective capacities, over various spans of time.

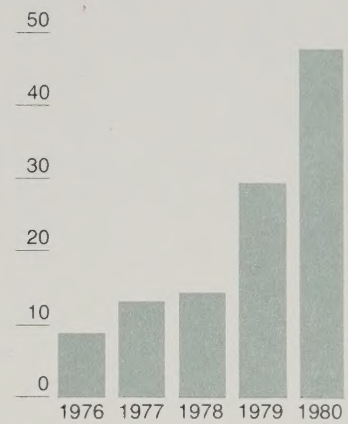
On this new threshold in the life of Total Petroleum, we look forward to the next five years, setting as a goal to improve on the record of the past five years. The growing competence and the steady dedication of our staff gives us the confidence that this goal will be met for the benefit of our shareholders.

On behalf of the Board of Directors

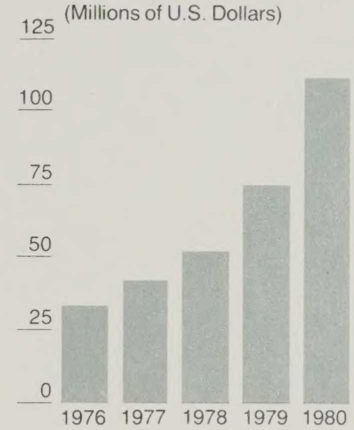


Philippe Dunoyer, President

Net Income
(Millions of U.S. Dollars)



Funds Provided by Operations
(Millions of U.S. Dollars)



Capital Expenditures
(Millions of U.S. Dollars)

Exploration and Production

Overview

Highlights of TOTAL's 1980 Exploration and Production operations are as follows:

- Cash flow from production rose to $62,338,000 versus $41,505,000 in 1979. This 50% increase is mainly due to rising prices and volumes in the United States.
- Additions to reserves by acquisition and exploration successes more than offset normal decline due to production.
- Oil production declined slightly to 10,400 barrels per day from 10,900 in 1979 while gas sales rose to 51.6 million cubic feet per day from 50.4 in 1979.
- Discoveries were made in the eastern Elmworth area (gas in the Doig formation), the offshore Texas gas plays, the deep Wilcox trend in the Gulf Coast area and in the Montana/Dakota region of the Williston Basin.
- In Canada, the new National Energy Program (NEP) has reduced incentives to explore and created much uncertainty in the oil industry. TOTAL's initial reaction has been to continue our exploration program in order to exploit our land position while awaiting further developments.
- In contrast, the U.S. policy of crude oil price decontrol has increased incentives to explore, but also increased competition for new leases and for drilling rigs.

Exploration and Development

CANADA

The main focus of TOTAL's exploration efforts in Canada continues to be in the Elmworth region of western Alberta. We also continue our exploration activities in other areas of Alberta and British Columbia.

Elmworth

TOTAL's most significant success in Canada during 1980 was in the eastern oil-prone (Wembley/Hythe) area of Elmworth. Each new exploratory well in the Elmworth area seems to bring unexpected, often good, results. Exploratory drilling resulted in the discovery of potentially significant gas reserves in the Doig formation below the oil-bearing Halfway sands. Preliminary estimates indicate up to 60 BCF of gas reserves in this area, of which TOTAL has an average 50% share. Currently, there is no market for this gas but the potential reserves remain as a long-term asset for TOTAL. Meanwhile, the development and extension of the Wembley oil field continues. TOTAL's share of production is now 510 barrels per day. Sales of gas through the Goodfare gas plant have reached 5 million cubic feet per day net to TOTAL.

Eastern Alberta

TOTAL continued an active and successful drilling program for shallow gas in the general Winefred/Heart Lake/Ironwood region of eastern Alberta, where a good success ratio prevails. TOTAL has an average 36% working interest in some 280,000 gross acres in this area and the average successful well yields from 0.5 to 1 BCF of reserves. While, again, there is no market for this gas, reserves are being developed at modest cost and the drilling extends the duration of our leases.

Heavy oil has also been found in this area and a technical review is currently underway to determine its potential for the future.

Other Areas

We encountered exploratory success showing good gas potential in the Helmet and Silverberry areas of British Columbia. Our drilling activity in the Red Earth area of Alberta has shown oil potential. We will increase our drilling at Red Earth this year in an effort to further define the discovery and to retain some leases due to expire in 1981. The restricted exploration budgets of some of our partners have given us an opportunity to increase our share in this play.

Drilling development well Rotary Camp 3-11 in northern Michigan.

In Labrador, where TOTAL decided a few years ago to be carried by farm out arrangements, no new discoveries were made and we continue our policy of being carried by reducing our interest in this area. In the Beaufort Sea, a well was partially drilled on acreage we farmed out to Dome Petroleum. Hopefully, this well will be re-entered in 1981 and drilled to an expected depth of 10,000 feet.

National Energy Program
The National Energy Program (NEP) formulated by the federal government in October 1980 will reduce production cash flow in Canada, at least for the near term. Many companies have sharply reduced their level of exploration activity for the current year, but TOTAL plans a level of expenditures and drilling activity in excess of our 1980 program in order to retain our prospective acreage. This decision has been based on our belief that our sizeable Canadian provincial acreage, which is not as drastically affected by NEP as federal frontier lands, continues to be a most attractive long-term asset. Our 1981 program, however, will be under continuing review on the basis of political and economic developments.

UNITED STATES
Exploration activities in the United States continued to emphasize our traditional areas of production while developing higher risk, higher potential prospects in new areas.

Michigan
In the Northern Michigan trend, where TOTAL has been producing oil and gas since the mid-1970's, projects for secondary recovery through use of water injection have commenced and are expected to increase production and add to existing reserves. We were also able to extend the known limits of the Rotary Camp field, where TOTAL has a 50% interest, by drilling two additional successful wells in 1980. This success not only added to primary reserves, but also enhanced prospects for secondary recovery operations. Two additional wells are planned for 1981.

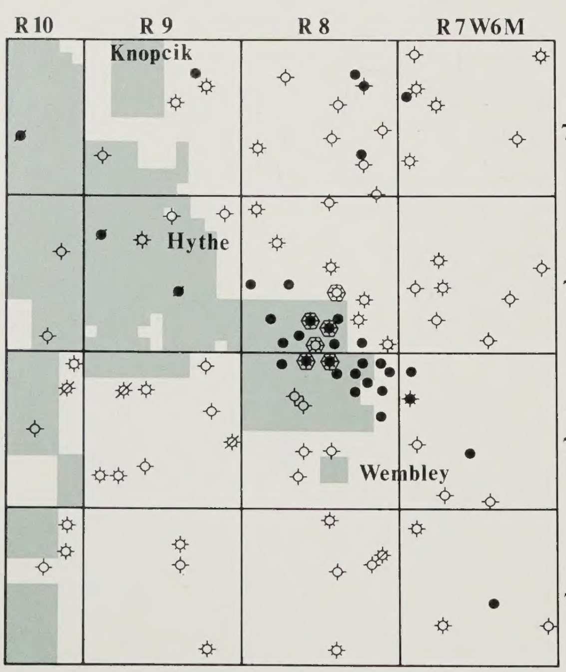
In Jackson County, along the Southern Michigan trend, we are applying new seismic modeling techniques and studying the sedimentation history in hopes of finding a way to extend this oil find made two years ago in a difficult geological environment.

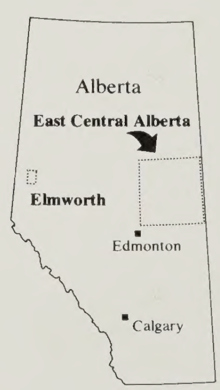
Williston Basin
For over ten years TOTAL has been actively exploring for oil in the Red River formation of the Williston Basin in the Dakotas and Montana. The good success ratio generally prevailing in this area (in excess of 50%) is enhanced by secondary objectives which often exist higher up in the wells. We hold an average 35% interest in about 200,000 acres in this area, some 30,000 of which have been added in recent years.

During 1980 TOTAL participated in drilling seven wells; four were completed as oil wells, one was dry and two are still drilling. We plan to spend about 25% of our 1981 U.S. drilling budget here and it is possible that we will increase our activity if additional rigs can be secured.

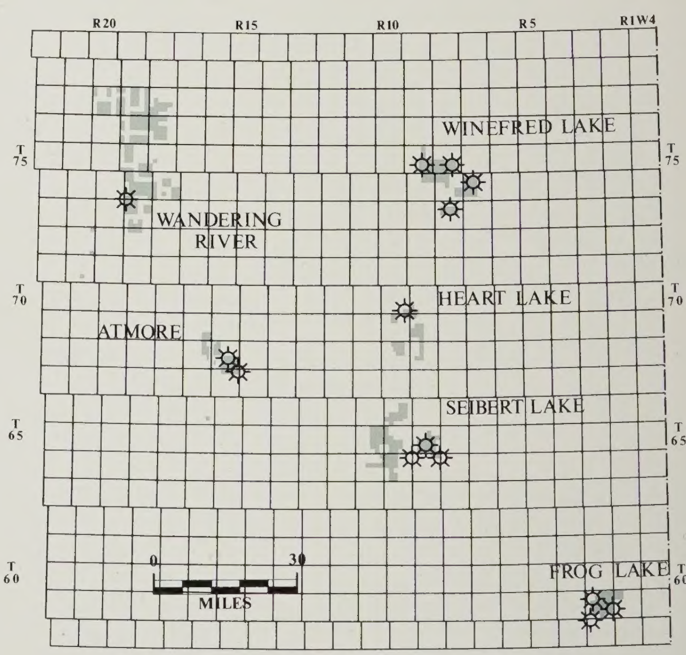
Gulf Coast Onshore
In the Gulf Coast area TOTAL had success in 12 of 17 development or stepout wells, most of which could be put on stream a few weeks after completion. More importantly, we made a significant gas discovery in the deep Wilcox formation in Duval County, Texas and are currently drilling another well to this formation in Wharton County. TOTAL re-

Elmworth Area (east)



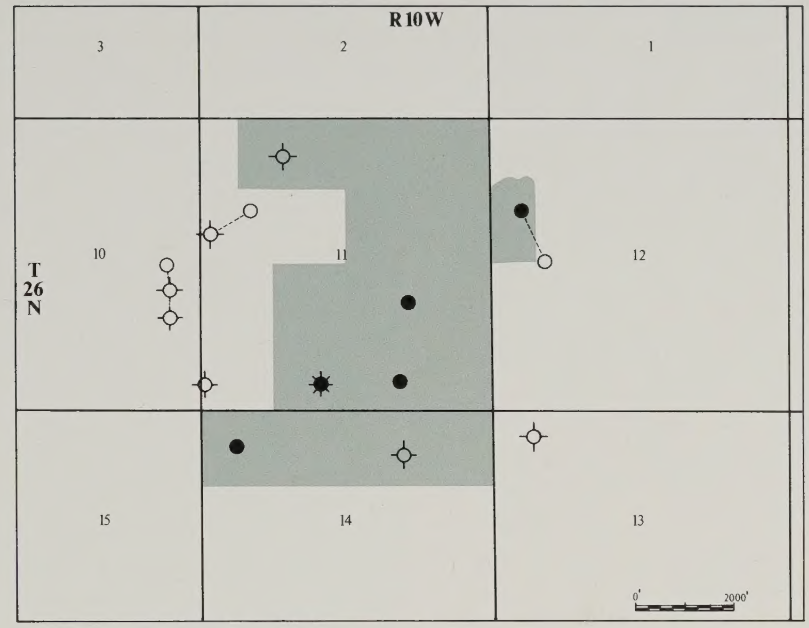


East Central Alberta



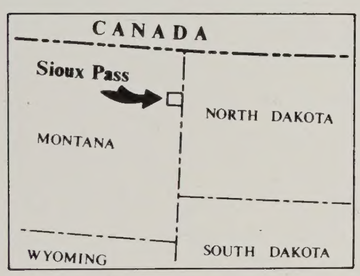
Rotary Camp & East Bay

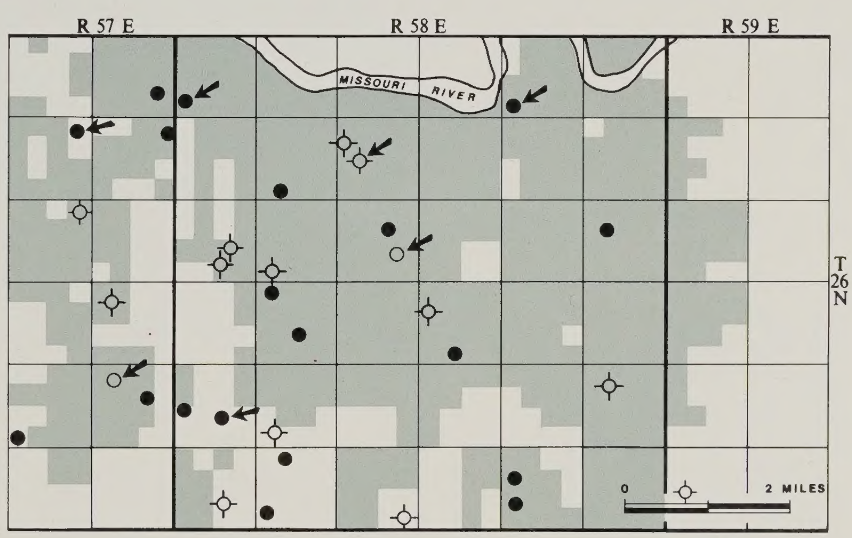
TOTAL Petroleum Land Holding
- Oil Well
- Gas Well
- Dry Hole



Sioux Pass Area

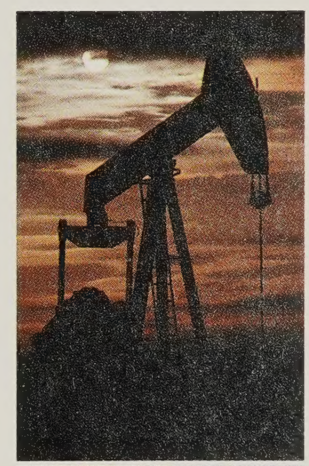
TOTAL Petroleum Land Holding
- Oil Well
- Dry Hole
- Drilling
- 1980 Well



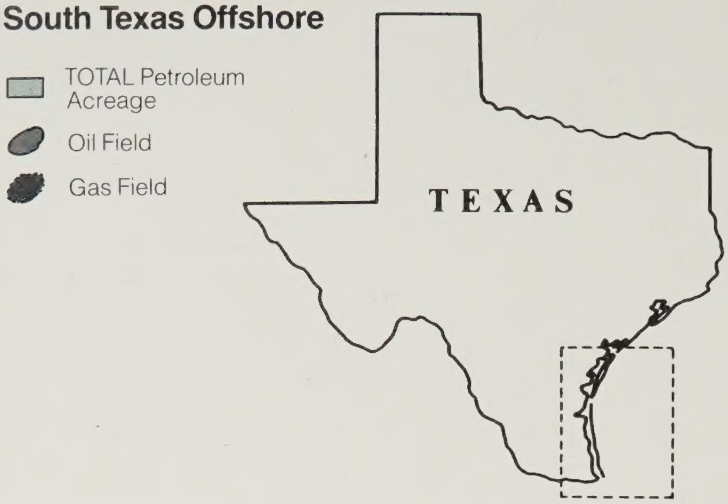


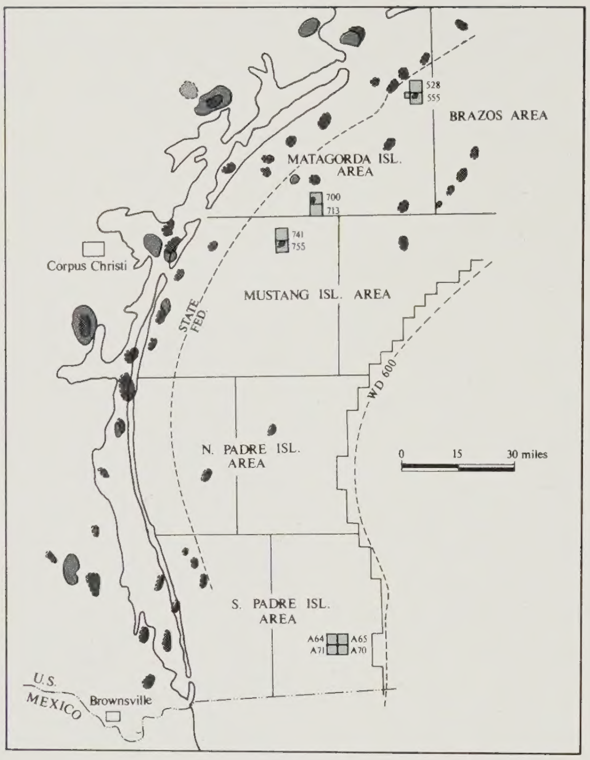
CONSOLIDATED LAND HOLDINGS ON DECEMBER 31, 1980
(Thousands of acres)

	Petroleum and Natural Gas Leases		Reservations, Permits and Licenses		Total	
	Gross	Net	Gross	Net	Gross	Net
British Columbia	561	181	109	28	670	209
Alberta	1,164	564	519	275	1,683	839
Saskatchewan	64	22	—	—	64	22
Ontario	43	22	—	—	43	22
Northwest Territories	82	55	656	162	738	217
Arctic	—	—	38	3	38	3
Labrador (Offshore)	—	—	22,025	1,101	22,025	1,101
Canada	1,914	844	23,347	1,569	25,261	2,413
Michigan	451	247	—	—	451	247
Texas	327	79	—	—	327	79
Louisiana	36	6	—	—	36	6
Rocky Mountain Area	1,021	234	—	—	1,021	234
All Other States	137	18	—	—	137	18
United States	1,972	584	—	—	1,972	584
Total	3,886	1,428	23,347	1,569	27,233	2,997



South Texas Offshore





tains a 50% working interest in both plays. We acquired a lease on 1,140 acres at Dauphin Island, Alabama, adjacent to a promising new trend in Mobile Bay where an apparent major discovery was made by others in 1979.

South Texas Federal Offshore
A discovery made in 1978 on Block 755 is now being developed and a production platform has been installed. TOTAL has a 10% working interest in this block and production is expected to start late this year. Two more recent gas discoveries were made in Blocks 700 and 555 where we have a small working interest. These discoveries are being evaluated and should be developed in 1981 or 1982.

After several years of limited activity in the offshore Texas area, a more aggressive approach has been taken recently with the acquisition of a 100% working interest in four blocks (over 20,000 acres) at a federal land sale in November 1980. We intend to drill on these blocks as soon as a rig is available, probably in early 1982. We have nominated several more blocks for the 1981 and 1982 sales.

The complete decontrol of crude oil prices in the U.S., the prospect of further relaxation of controls on natural gas, and the immediate access to market of oil and gas confirm our decision to become more aggressive in the United States.

Production and Reserves

CANADA
Canadian oil production declined in 1980, mainly due to prorationing. A further decline in 1981 is likely, particularly if the reduced production levels mandated on March 1, 1981 by the Alberta provincial government as part of its dispute with the federal government over the NEP continue over an extended period of time. Gas production also declined slightly in Canada, mainly due to the lack of market.

Canadian oil reserves declined about 8% as a result of normal production. Gas reserves increased by 6% over 1979 levels. At current production rates, Canadian gas reserves would last 29 years, an increase from 27 years in 1979. When a market develops for Canadian gas, we are in a position to significantly increase our reserves through development drilling. Understandably, we and the industry

PRODUCTION STATISTICS

Crude Oil Production
(before royalties)

	1980				1979			
	Bbls.	BPD	Revenue Per Bbl. (i)	Cash Flow Per Bbl. (ii)	Bbls.	BPD	Revenue Per Bbl. (i)	Cash Flow Per Bbl. (ii)
Canada	2,114,694	5,778	$13.47	$ 6.61	2,336,173	6,400	$11.33	$ 5.69
United States	1,701,489	4,649	$20.11	$11.72	1,641,240	4,497	$13.16	$ 8.38
Total	3,816,183	10,427			3,977,413	10,897		

Natural Gas Sales
(before royalties)

	1980				1979			
	MCF	MCFPD	Revenue Per MCF (i)	Cash Flow Per MCF (ii)	MCF	MCFPD	Revenue Per MCF (i)	Cash Flow Per MCF (ii)
Canada	8,011,670	21,890	$ 2.32	$ 1.31	8,062,000	22,088	$ 1.62	$ .86
United States	10,880,607	29,728	$ 2.17	$ 1.36	10,328,000	28,296	$ 1.64	$ 1.04
Total	18,892,277	51,618			18,390,000	50,384		

(i) Average revenue per barrel or MCF, before royalties, stated in U.S. dollars.
(ii) Revenue per barrel or MCF less royalties and operating costs.

are reluctant to develop gas reserves with no immediate prospects for cash flow.

UNITED STATES

As a result of exploration successes and the acquisition of the producing properties of Traverse Corporation, both oil and gas production increased and reserve additions more than offset normal production declines. Future increases in gas production and reserves are expected as several early 1981 Gulf Coast discoveries, onshore and offshore, in which we have an interest are due to come on stream.

The Production Statistics table on page 8 dramatically illustrates the difference between U.S. and Canadian policies. The cash flow per barrel of oil was 50% higher in the U.S. than in Canada in 1979, 80% higher in 1980, and the gap will grow bigger in 1981 as decontrol in the U.S. will increase and the NEP in Canada will probably decrease cash flow. Cash flow per MCF of gas is more comparable because of continued price controls in the U.S. Nevertheless, the trend is in favor of the U.S. Besides, new discoveries in the U.S. can immediately be put on stream and contribute to cash flow, whereas new discoveries of natural gas in Canada remain shut-in for lack of market.

As stated in the Overview, total reserve additions during the year, on an energy equivalent basis (1 bbl. of oil = 6 MCF of gas), exceeded production. Over the past five years TOTAL has increased its energy reserves in the ground, contrary to the industry trend.

Outlook

In spite of current adverse economic conditions in Canada, the geologic potential of our Canadian land holdings is such that we still consider them a very attractive long-term asset, which we plan to maintain and enhance. While decontrol in the U.S. has heightened competition, it has also increased the potential rewards of exploration. We believe that our consistent, long-term oriented attitude in Canada and our more aggressive approach in the United States put us in a good position to capitalize on the opportunities of the future.

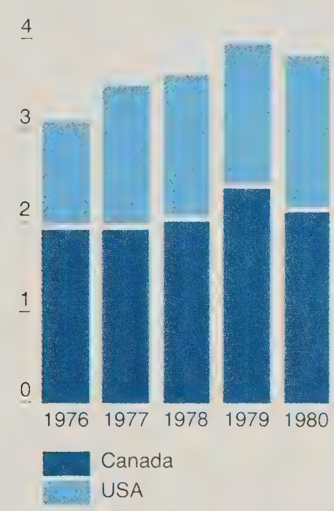
DRILLING ACTIVITY

Exploratory Wells		1980		1979	
		Gross	Net	Gross	Net
Canada	Oil	5	1.8	2	1.2
	Gas	30	7.5	17	3.7
	Dry/suspended	35	8.1	27	9.1
		70	17.4	46	14.0
United States	Oil	4	.6	4	1.7
	Gas	1	—	8	1.6
	Dry/suspended	16	5.6	23	10.7
		21	6.2	35	14.0
Total exploratory wells		91	23.6	81	28.0

Development Wells		1980		1979	
		Gross	Net	Gross	Net
Canada	Oil	4	2.0	8	4.0
	Gas	3	.7	2	.3
	Dry/suspended	1	.7	3	1.7
		8	3.4	13	6.0
United States	Oil	23	5.1	20	5.7
	Gas	18	2.2	13	2.0
	Dry/suspended	14	4.0	8	2.6
		55	11.3	41	10.3
Total development wells		63	14.7	54	16.3
Total wells		154	38.3	135	44.3

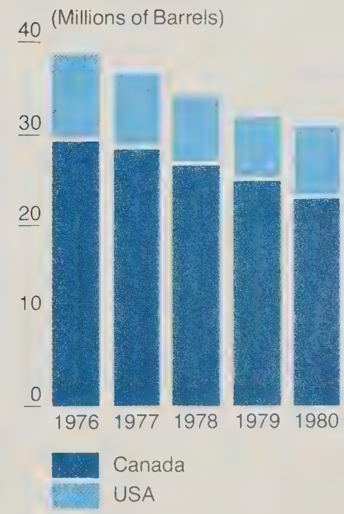
Oil Production

(Millions of Barrels Per Year)



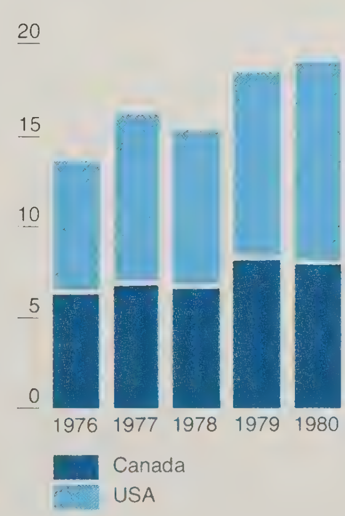
Remaining Proved Oil Reserves

(Millions of Barrels)



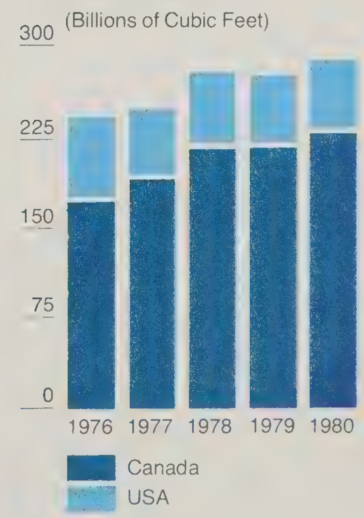
Natural Gas Sales

(Billions of Cubic Feet Per Year)



Remaining Proved Gas Reserves

(Billions of Cubic Feet)



Refining and Marketing

Overview

As mentioned in the President's letter, TOTAL made its largest ever acquisition investment in October 1980 with the purchase of Vickers Petroleum Corporation. The addition of the 64,000 barrels per day refinery located in Ardmore, Oklahoma plus 350 company-operated service stations in the mid-continent area increases refining capacity by 70% to 150,000 barrels per day and nearly doubles refined product sales.

Cash flow from the refining and marketing segment of our operations was $86 million in 1980 compared to $58 million in 1979 and $30 million in 1978. The improvements in cash flow reflect our continuing efforts to increase gasoline yields from crude oil processed and to improve the efficiency of our marketing and distribution systems. The strong product margins enjoyed by the refining industry throughout most of 1980 also had a positive effect on cash flow.

Other highlights of 1980 operations are as follows:

- The Alma and Arkansas City refineries operated at capacity, equalling the 1979 throughput volumes.
- The final phase of the Arkansas City modernization program was completed at year-end. This phase will commence operations in early 1981, and consists of a prototype fluid catalytic cracking unit designed to upgrade residual fuel to gasoline and middle distillates. The facility will raise gasoline yields to about 70% of refinery charge stock.
- Projects were completed at the Alma refinery to increase catalytic reforming by 40% and further expand residual oil cracking by 12%. These projects increase our ability to produce unleaded gasoline and allow the purchase of outside residual fuel for upgrading to gasoline.
- Retail marketing operations benefited from increased volumes per station and from sales of other merchandise.

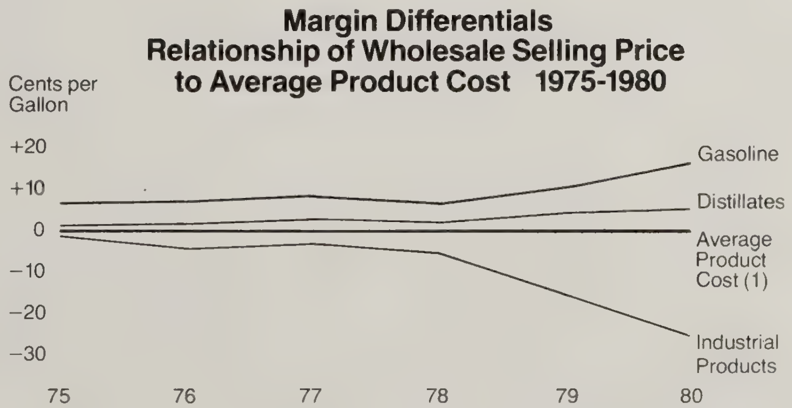
Under the following subheadings of Refining and Supply and Marketing, we will discuss how expansion and acquisitions of the past 5 years have positioned TOTAL to take advantage of the changing markets of the 1980's.

Refining and Supply

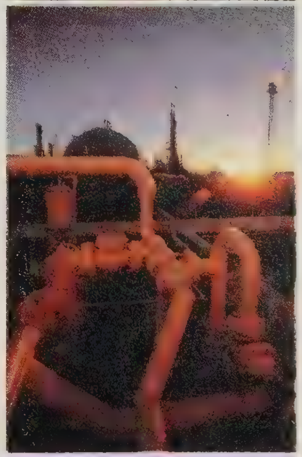
Five years ago, the company's refining and marketing operation was essentially limited to the state of Michigan. Crude oil runs at the Alma refinery were about 37,000 barrels per day. This compares to an average refinery charge of 144,000 barrels per day in late 1980, including the newly acquired Ardmore refinery.

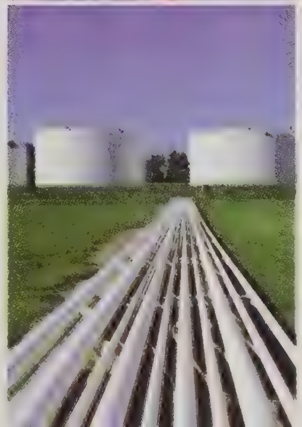
Besides the volume increase of refinery charge, the other major factor increasing cash flow from refining has been our ability to increase yields of gasoline and light fuel oils at the expense of industrial products. Upgrading and modernization improvements have been in operation at the Alma refinery since 1978 and were completed at the Arkansas City refinery in early 1981. We will shortly begin construction of a residual oil cracker at the Ardmore refinery. Some of the features of our upgrading process are proprietary and we have applied for patents.

Margin differentials between gasoline and industrial oils (see graph on this page) are the reasons for greatly increased cash flow from upgrading. Margins, or average wholesale selling price less average refined product cost, have changed dramatically in the past few years. Gasoline and light fuel oils have historically sold for more than average product costs while industrial products have sold at a loss. During the period 1975 to 1978, residual fuel oil sold at an average 5 to 10 cents per gallon less than gasoline. As crude oil prices rose rapidly, gasoline and distillate prices went along and exceeded the rise in crude oil prices. However, residual oil and industrial product prices fell further behind. They rose, but not as fast as crude oil costs. Competition with alternate fuels — natural gas and coal — and generally reduced demand for industrial prod-



(1) Average product cost includes cost of crude oil and other charge stock plus refinery expenses.





TOTAL's newly acquired Ardmore, Oklahoma, refinery.

ucts because of conservation and slow economic conditions have combined to limit the prices of these products. As a result, the average price differential between gasoline and residual oil widened to 25¢ per gallon in 1979 and to over 40¢ per gallon in 1980.

While these margin differentials cannot be expected to last over an extended period of time, they are expected to remain well above the 5 to 10 cents per gallon historical average. The economics of upgrading to maximize gasoline production are readily apparent. By converting one gallon of black oil into a gallon of gasoline, we generate an extra 25¢ or more of cash flow. From experience at Alma and projections at Arkansas City and Ardmore, our upgrading programs can be expected to convert approximately 15% of total refinery charge from industrial fuels to gasoline. With an expected average refinery charge in excess of 2 billion gallons per year, this leverage will be a large factor in future cash flow.

Over the past five years, crude oil supply has become a major factor in refinery operations. Prior to the acquisition of the Ardmore refinery, we were able to operate our refineries essentially at capacity with domestic crude oil meeting about 60% of our requirements and the remainder in foreign crude oil secured through an affiliate of Compagnie Française des Pétroles at regular contract prices.

Because of the crude oil gathering systems connected with each of our refineries, our domestic crude oil supply appears fairly stable, at about 40% of our expanded requirements. The foreign supply mentioned above will provide about 30% of our expanded needs. The remaining 30% will be obtained on short-term contracts. Having over two-thirds of our requirements available on a fairly secure basis puts us in a more favorable position than many independent refiners.

Marketing

Through acquisitions and growth of existing operations, TOTAL's refined product sales have increased from 0.7 billion gallons in 1976 to 1.7 billion gallons in 1980. Of particular importance, sales of gasoline, the most profitable refined product, grew from 0.5 billion gallons in 1976 to 1.2 billion gallons in 1980. These sales volumes include only three months of the newly acquired Vickers operations.

In retail operations, TOTAL's average monthly volume at company-operated service stations increased by 45% between 1976 and 1980 to more than 125,000 gallons per station. The major factor in this growth is the conversion of our stations to the very popular self-service, high volume type of marketing. With today's high gasoline prices, the public is increasingly taking advantage of the savings which are available to them under this cost efficient method of retailing. As a result of the growth in volume and the labor savings from self-service, TOTAL's direct operating expenses at the service station level have remained virtually unchanged on a cents-per-gallon basis from 1976 to 1980 despite significant dollar cost increases in this highly inflationary period.

Another important strength in TOTAL's retail operations is the growth in the sales of other merchandise items, such as cigarettes, soft drinks and motor oil. Since 1976, TOTAL's profit on other merchandise has grown to more than 1½¢ per gallon of gasoline sold. We believe other merchandise sales are a key factor in retail profitability, particularly during periods of volatile gasoline margins. This is also the most efficient use of available space in service station buildings.

The recent Vickers acquisition greatly increased the size and geographic spread of our retail operations. Prior to the acquisition, TOTAL's retail operations consisted of approximately 130 TOTAL and BEST brand stations in Michigan and Wisconsin to which were added 350 VICKERS brand stations in an 18-state area. The Vickers stations are also company-operated self-service type outlets with an average monthly volume in excess of 150,000 gallons per station. Many of the better locations, such as Denver, Phoenix and Dallas, are in areas of the country that are growing faster than TOTAL's former market. We have already made some changes by consolidating and streamlining both operations and by converting some of the lower volume outlets to jobber operations. In addition, we intend to make physical improvements to the Vickers stations and to expand the sales of other merchandise through them. We believe that these actions will further improve the profitability of this already successful network. The Vickers acquisition has also given us a more balanced mix of gasoline sales, with retail sales now accounting for about 45% of total gasoline sales.

Despite success in retail operations, TOTAL remains committed to its branded jobber operation as well. Through acquisition and growth, gasoline sales to branded jobbers increased from 79 million gallons in 1976 to 469 million gallons in 1980. Even prior to the termination of government controls, TOTAL was offering three-year contracts to branded jobber accounts. This entire volume, plus a significant volume of unbranded sales, was handled by a staff of only 23 with a resultant 1980 marketing overhead cost of less than $.0015 per gallon.

The acquisition of Vickers added approximately 100 million gallons per year of branded jobber gasoline sales. These jobbers are presently being converted to the APCO brand and offered three-year contracts. Because of the overlap of marketing territories, the added jobber and unbranded volume of gasoline and distillates required a minimum addition to our existing staff, thus further reducing our cost per gallon for this segment of our operation.

TOTAL is now in the process of designing and issuing a single credit card which will be honored in all of its TOTAL, APCO, BEST and VICKERS outlets. Credit card operations will be consolidated in a single credit card center located in Alma, Michigan. This consolidation will result in reduced unit costs of handling expensive credit card operations.

Outlook

While TOTAL has enjoyed substantial growth through expansion and acquisition over the past five years, certain future problems must be faced:

- Crude oil availability may become tight again.
- Gasoline demand is expected to continue to fall.
- Crude oil and refinery operating costs will continue to rise.
- The selling price of asphalt

Average Monthly Station Volume Company Operated Retail Network

The Company markets under the TOTAL, APCO, BEST and VICKERS brand identification.

and residual fuel will continue to lag behind crude oil costs.

- The termination of price and allocation controls in January 1981 will have lasting effects on competitive conditions in the marketplace.

TOTAL's strategy in coping with these various problems is basically to continue what we have practiced for the past several years:

Improve Gasoline Yields
As already mentioned, we will shortly begin construction of a residual oil cracker at the Ardmore refinery. Its completion in 1982 will raise Ardmore's gasoline yield to approximately 68% vs. the current 52%. This facility will also raise our aggregate cracking capacity to over 45% of crude capacity.

Other Charge Stocks
In the anticipation of ever increasing crude oil costs and tightening crude oil availability, we have concentrated on increasing our ability to utilize other feedstocks. During 1981 other feedstocks such as gas liquids and residual fuels will approximate 10% of runs and possibly approach 15% in 1982.

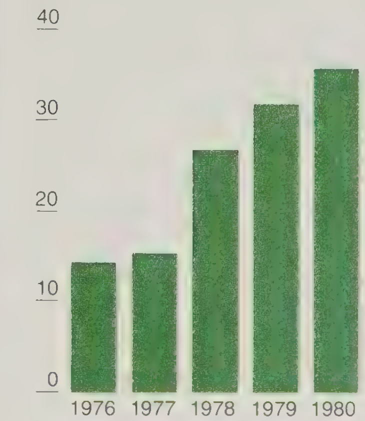
Crude Oil Cost and Availability
The company's ability to process less expensive and more readily available sour and heavier crude oils will improve substantially at the Arkansas City and Ardmore refineries following the commissioning of the residual oil crackers.

Gasoline Production Versus Demand
Our current gasoline sales exceed our production by about 30%. The shortfall is supplied through outside purchases. As a result of upgrading programs at our refineries the production shortfall is expected to drop to 10-15%, resulting in a reduction of outside purchases. Should our sales decline in line with many industry forecasts of 10-15% over the next several years, we would further reduce outside purchases and thereby be able to continue to operate our refineries at capacity.

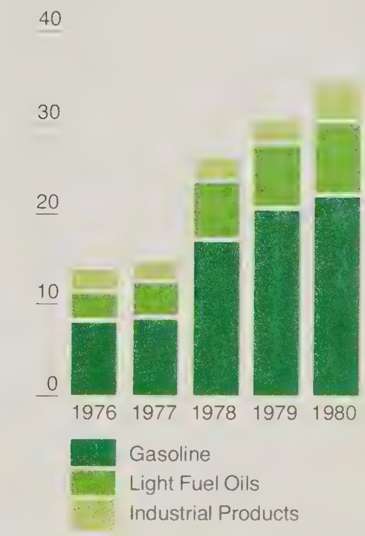
Competition in the Marketplace
The "free market" situation experienced by the industry following decontrol is leading to changes in the marketplace. Prior to decontrol, competitive conditions were already such that refiners and marketers were far from able to recoup the margins allowable under federal regulations. Under decontrol, competition will intensify. From a marketing standpoint, another major effect of decontrol will be the freedom that gasoline wholesalers and retailers will have in changing suppliers. We believe that, due to TOTAL's excellent relationship with its jobbers and to the efficiency of its retail operations, the company is well prepared to deal with changes resulting from decontrol.

As pointed out in the President's letter, refining and marketing margins suffered a reduction during the initial period of adjustment to decontrol. For the longer term, we are confident that the growth and the improvements in efficiency accomplished in our refining and marketing operation during the past five years have made it very competitive and capable of maximizing opportunities in 1981 and beyond.

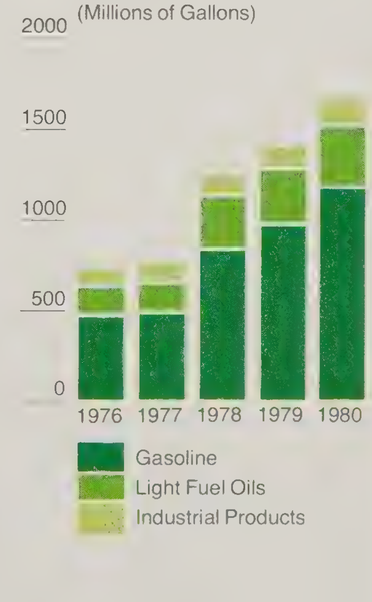
Refinery Inputs
(Millions of Barrels)



Refinery Production
(Millions of Barrels)

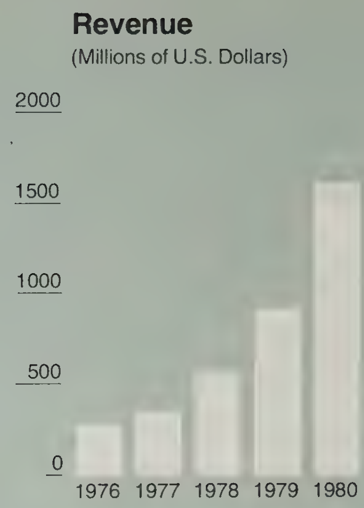


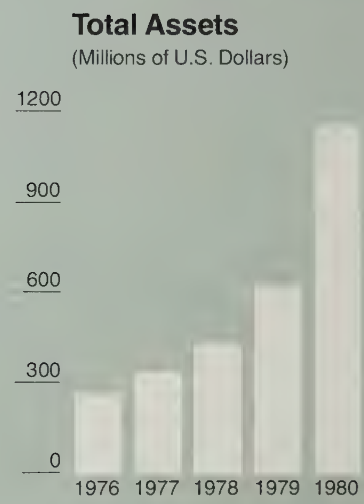
Refined Product Sales
(Millions of Gallons)

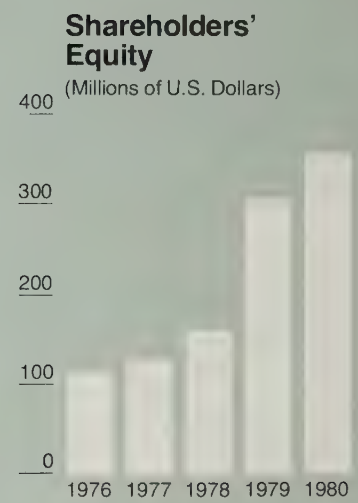


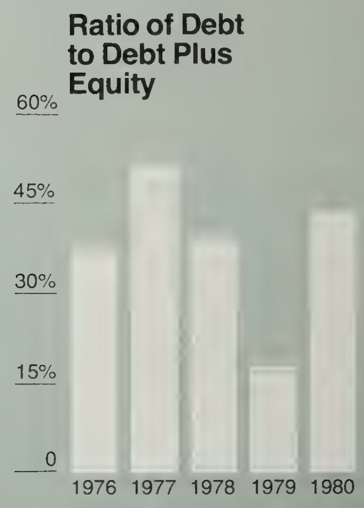
Financial Section

CONTENTS









Selected Five-Year Data

		1980	1979	1978	1977	1976
FINANCIAL (in thousands of U.S. dollars, except per share amounts)						
	Revenues	**$1,604,537**	$910,505	$572,310	$349,469	$298,718
	Net income	**47,749**	29,871	14,416	12,964	8,846
	Net income per share	**2.30**	1.82	.98	1.01	.69
	Dividends per common share (Can.$)	**.44**	.29	.15	.05	—
	Funds provided by operations	**110,681**	75,029	51,579	42,357	32,953
	Capital expenditures	**66,866**	54,262	50,246	40,998	35,041
	Acquisition expenditures	**306,407**	—	48,025	9,850	47,611
	Total assets	**1,155,017**	624,262	440,554	346,690	264,272
	Long-term debt	**278,060**	68,542	109,868	134,807	71,059
	Shareholders' equity	**357,879**	306,565	163,476	129,017	117,144
	Ratio of debt to debt plus equity	**44%**	18%	40%	51%	38%
OPERATING						
Exploration and Production	Crude oil and condensate (thousands of barrels)—					
	Canada					
	Proved reserves at year-end	**22,864**	24,786	26,708	28,176	29,110
	Production during year	**2,115**	2,336	2,020	1,929	1,937
	United States					
	Proved reserves at year-end	**7,867**	7,022	7,240	8,614	9,390
	Production during year	**1,701**	1,641	1,578	1,628	1,172
	Natural gas (millions of cubic feet)—					
	Canada					
	Proved reserves at year-end	**227,726**	215,809	213,937	190,389	176,040
	Sales during year	**8,012**	8,062	6,800	6,876	6,202
	United States					
	Proved reserves at year-end	**60,380**	59,092	62,066	59,860	68,360
	Sales during year	**10,880**	10,328	8,505	9,319	7,379
	Gross land holdings (thousands of acres)—					
	Canada	**25,261**	25,235	28,626	32,092	32,031
	United States	**1,972**	2,124	2,401	2,641	2,547
	Net land holdings (thousands of acres)—					
	Canada	**2,413**	2,427	2,774	2,972	2,972
	United States	**584**	658	633	728	792
Refining and Marketing	Refinery input (thousands of barrels)	**35,652**	31,829	26,873	15,317	14,365
	Manufactured gasoline (thousands of barrels)	**21,818**	20,402	16,573	8,074	7,305
	Refined product sales (thousands of barrels)	**39,560**	33,378	29,525	17,884	17,478
	Gasoline sales (thousands of barrels)	**27,815**	22,967	20,088	11,407	10,986

Financial Review

Overview

Funds provided by operations, the most meaningful measure of our performance, were $110,681,000 in 1980, a 47% increase from $75,029,000 in 1979. Net income increased to $47,749,000, or $2.30 per share, up from $29,871,000, or $1.82 per share, in 1979. Factors which affected funds provided by operations and earnings are analyzed in the Management Discussion and Analysis appearing on the following pages.

The most significant financial event in 1980, except for increased net income and funds provided by operations, was the large acquisition of refining and marketing properties late in the year. The acquisition and the related financing arrangements are described in Note 2 of Notes to Consolidated Financial Statements.

In recent years, the SEC has greatly expanded its requirements for information which must be filed with the Commission. Information regarding accounting for exploration and production activities and accounting for inflation, most of which was also required in 1979, is of particular interest. A detailed discussion of these subjects can be found in Notes 12 and 13 of the Notes to Consolidated Financial Statements.

Financial Structure

TOTAL's flexible financing structure was needed, and was used, in 1980 for the purchase of Vickers Petroleum Corporation. Availability of unsecured debt financing totaling more than $300 million was arranged with relative ease, because good earnings and the 1979 preferred share issue of $140 million (Can.) had created a very strong balance sheet.

Although the ratio of debt to debt plus equity was 44% at the end of 1980, TOTAL still has substantial borrowing capacity and is still financially flexible. Oil and gas reserves which are not pledged could be used to secure a substantial amount of new debt.

The $10 warrants issued in 1976 expired at December 31, 1980, and 1,588,445 (97% of the issue) were exercised before that date, adding $15,884,000 of new equity.

Market Information and Dividends

Principal markets for the Company's common shares (TPN) are the Toronto Stock Exchange in Canada and the American Stock Exchange in the United States. There were approximately 6,424 holders of record of the Company's common shares on March 5, 1981. The quarterly dividend on the common shares was increased from $.08 (Can.) to $.12 (Can.) in the second quarter of 1980. The Board of Directors increased the dividend because net income and cash flow had improved and were expected to continue at levels which would adequately support such a dividend, while preserving TOTAL's ability to pursue its many opportunities for reinvestment of its cash flow.

The high and low sales prices of the common shares and the dividend paid during each quarterly period were as follows:

		1979				1980			
		1	2	3	4	1	2	3	4
Toronto Stock Exchange	High	25⅝	31¾	30⅝	31⅜	36½	31	30½	32¼
(Can. $)	Low	17½	22	23¾	20½	20	23	26	24¼
American Stock Exchange	High	22	27¼	26¼	26⅞	31⅞	27	25⅝	27⅝
(U.S. $)	Low	14¾	19¼	20½	17⅛	16¼	21⅝	22¼	22½
Dividend per share (Can. $)		.05	.08	.08	.08	.08	.12	.12	.12

The Canadian government imposes no limitations on rights of United States persons holding equity shares in the Company. The Income Tax Act Canada provides for the withholding of a 25% tax on dividends paid to a non-resident by a Canadian corporation. The Act also provides that where a corporation which paid a dividend has a specified degree of Canadian ownership the amount of tax otherwise payable is reduced by 5%. Article XI of the Canada-United States reciprocal tax convention (which takes precedence over the Income Tax Act Canada) states that the withholding rate of income tax shall not exceed 15%. Therefore, because of the Canadian ownership provisions of the Income Tax Act Canada and the reciprocal tax convention, the rate of withholding applicable is reduced to 10%.

Capital Expenditures

Capital expenditures in 1980 were $373 million, including $306 million for two acquisitions. Again, as in 1979, cash flow was not completely reinvested into existing businesses. Refining-marketing cash flow exceeded expectations and the excess cash flow helped reduce the amount of debt incurred for the Vickers acquisition.

The 1981 capital expenditure program amounts to about $100 million, of which approximately two-thirds is allocated to exploration and production.

Quarterly Results

The following summarizes certain quarterly financial information for 1980 and 1979 (in thousands of U.S. dollars except per share amounts):

	Quarter Ended				
1980	March 31	June 30	September 30	December 31	Total
Revenue	$314,589	$326,531	$313,548	$649,869	$1,604,537
Contribution to profit*	18,805	38,655	27,937	20,036	105,433
Provision for income taxes	7,300	16,500	10,800	500	35,100
Net income	8,071	18,291	14,261	7,126	47,749
Net income per share	.38	.89	.69	.33	2.30
1979					
Revenue	$174,050	$205,392	$251,600	$279,463	$ 910,505
Contribution to profit*	11,004	10,906	22,589	20,836	65,335
Provision for income taxes	2,900	3,200	9,900	5,900	21,900
Net income	4,730	4,591	9,124	11,426	29,871
Net income per share	.29	.28	.56	.68	1.82

*Income before interest charges and provision for income taxes.

Net income for the fourth quarter of 1980 includes approximately $4 million of income related to a downward revision of income tax rate from that applied in earlier quarters and other adjustments. The fourth quarter of 1979 included income of approximately $2.8 million because of a downward revision in depletion and income tax rates and other adjustments.

Management Discussion and Analysis

The following discussion includes a brief description of significant factors affecting the Company's operations, its liquidity and financial flexibility. The financial statements and the table of Selected Five-Year Data provide financial and operating information for the past five years and should be read in conjunction with this discussion.

Operations

The Company has two operating divisions—exploration and production operates in Canada and the United States, and refining and marketing operates in the United States. The Statement of Information by Industry Segment and Geographic Area ("the Statement") presents funds provided by operations, revenues and operating profit with details for amounts directly attributable to the divisions. Certain administrative expenses and certain amounts included in the other income account are incurred at the corporate level and, accordingly, are not allocated to the divisions. Interest and income tax expense are also not allocated.

Exploration and Production

Funds provided by operations of the exploration and production division increased in each of the five years presented in the Statement. Increasing sales prices have been the principal reason for the rising trend of funds provided by the division. The following table is an analysis of the increase in funds provided by exploration and production operations for 1980 compared to 1979 and 1979 compared to 1978 (in thousands of U.S. dollars):

	1980			1979		
	Canada	U.S.	Total	Canada	U.S.	Total
Increased sales revenues (net of royalties) due to:						
Sales quantities	$(1,495)	$ 3,442	$ 1,947	$3,494	$ 669	$4,163
Sales prices	6,127	16,032	22,159	987	3,611	4,598
Other income	(30)	(210)	(240)	451	165	616
	4,602	19,264	23,866	4,932	4,445	9,377
Increased operating and administrative expenses	(745)	(2,288)	(3,033)	(927)	(1,357)	(2,284)
Total increase in funds provided	$ 3,857	$16,976	$20,833	$4,005	$3,088	$7,093

Sales quantities were fairly constant during 1977 and 1978 but increased materially in 1979. Sales quantities increased again in 1980 but at a much smaller rate than the 1979 increase. Canadian crude oil production increased in 1979 due to western Canadian crude oil replacing crude oil imports in eastern Canada. Increased world crude oil supply in 1980 reduced the flow of western Canadian crude oil to the east and prorationing of production has again become a limiting factor to Canadian crude oil sales. Even though the Company has abundant natural gas production

capacity in Canada, market conditions during 1980 held natural gas sales at a level similar to 1979. We expect that the recent National Energy Program, and provincial reactions which it has caused, will be a constraint to Canadian crude oil and natural gas sales in 1981. Increased sales quantities in the U.S. accounted for all of the 1980 increased revenues attributable to this factor. Production from properties acquired from Traverse Corporation in early 1980 was the principal reason for increased sales quantities.

As can be seen in the above table, ''phased decontrol'' of crude oil prices in the U.S. during 1980 had a dramatic impact on the Company's funds provided from the U.S. exploration and production operations. Average funds provided per barrel of crude oil in the U.S. increased from $8.38 in 1979 to $11.72 in 1980, a 40% increase. Average funds provided per thousand cubic feet of natural gas in the U.S. increased 31% from $1.04 in 1979 to $1.36 in 1980. These increases should continue in 1981 as a result of complete decontrol of crude oil and continuing gradual decontrol of natural gas.

In Canada, despite the federal government's approach to energy economics, prices have been allowed to increase. Higher export prices for natural gas have been the principal contributing factor to increased funds from Canadian production. Average funds provided per thousand cubic feet of natural gas increased from $.86 in 1979 to $1.31 in 1980, a 52% increase. On the other hand, funds provided per barrel of crude oil increased only 16%, from $5.69 in 1979 to $6.61 in 1980.

Depreciation and depletion attributable to the exploration and production division increased $9.6 million in 1980 after increasing slightly in 1979. This expense increases as production quantities increase and is also affected by the higher cost to find and develop mineral reserves. Note 12 of Notes to Consolidated Financial Statements provides additional information relative to costs incurred, production volumes and recorded depletion expense.

Refining and Marketing
Funds provided by refining and marketing operations have grown steadily during the five year period presented in the Statement, principally because of more favorable margins in each year compared to the prior year and acquisitions in 1978 and 1980. Starting in 1978, each year reflects the increased volumes related to the acquisition of the Arkansas City, Kansas refinery (acquired April 1, 1978). The year 1980 reflects three months of the refining and marketing operations acquired from Vickers Petroleum Corporation on October 2. Sales volumes of the Vickers operations for the last three months of 1980 were 280 million gallons or 17% of the Company's 1980 sales volumes. Gross margin per gallon from refining and marketing operations (net sales of refined products less purchased crude oil, products and merchandise — divided by sales volume) has increased from 7.3¢ in 1976 to 13.9¢ in 1980. This margin growth occurred even though market conditions for refined products fluctuated during the years, reflecting short-term variations in supply/demand relationships and the effects of extensive government regulation.

The following table provides details of the increase in funds provided by the refining and marketing division for 1980 compared to 1979 and 1979 compared to 1978 (in thousands of U.S. dollars):

	1980	1979
Increased revenues:		
Sales increased due to —		
Sales quantities	$151,720	$ 62,000
Sales prices	507,295	269,677
Increase in other income	1,207	473
	660,222	332,150
Increased cost of purchased crude oil, products and merchandise due to:		
Purchase quantities	(146,168)	(46,211)
Purchase prices	(434,478)	(236,540)
	(580,646)	(282,751)
Increased operating, marketing and administrative expenses	(51,680)	(21,431)
Total increase in funds provided	$ 27,896	$ 27,968

As indicated previously, both 1980 and 1979 benefited from increased sales volumes and improved margins. Sales resulting from the Vickers Petroleum acquisition accounted for approximately $160 million of the 1980 increase in revenues due to sales quantities and approximately $110 million due to sales prices (based on 1979 average prices). Excluding increases from acquisitions,

revenue increases due to sales prices in 1980 and 1979 were approximately $396 million and $260 million respectively. These increases reflect not only increasing selling prices of individual products but, more importantly, reflect a mix of products sold which includes a growing percentage of higher sales value products. The Company's upgrading programs at its refineries have dramatically increased the saleable yield of higher sales value gasoline and light fuel oils, replacing lower sales value residual fuel oil and asphalt. Refinery upgrading has contributed significantly to the increased margins over the last three years. A $15 million upgrading program at the newly acquired Ardmore, Oklahoma refinery is presently underway and, when completed in 1982, will further improve refined product margins.

It is difficult to predict with confidence 1981 results from the refining and marketing operations. During late 1980 and early 1981 margins have been reduced because weak demand has kept product selling prices from increasing as rapidly as crude oil costs. Crude oil costs have escalated due to OPEC price increases and decontrol of domestic crude oil prices. Some time will be needed to establish a new equilibrium between the cost of crude oil and the price of finished products. The duration of this adjustment period will determine, in large measure, the funds provided from 1981 operations.

Operating, marketing and administrative expenses other than those related to the acquired Vickers operations increased by 33% in 1980 compared to 1979. More than one half of this increase was caused by higher refinery fuel cost. The 1980 increase in operating, marketing and administrative expense related to the Vickers operations was approximately $19 million. Depreciation expense for refining and marketing assets in 1980 increased by $6.9 million from 1979, principally because of depreciation of the acquired assets.

General

Interest expense rose sharply in 1980 due to the financing for the Vickers Petroleum acquisition and for additional working capital requirements. This expense is expected to increase materially in 1981 since the borrowings required for the acquisition were outstanding for only three months of 1980.

Income tax expense tends to vary directly with net income before deduction for income tax expense. The effective tax rate in 1980 in both the United States and Canada remained at a level similar to 1979. Correspondingly, the 1980 income tax expense increased significantly from 1979 due to higher income before deduction for income tax expense.

Unallocated administrative expenses for 1980 include $2,000,000 for the cost of closing offices and related employee terminations. During 1981 the Company will relocate its executive headquarters from Alma, Michigan to Denver, Colorado. Costs related to this relocation will be expensed in 1981.

A discussion of the effect of inflation and changing prices on net sales and revenues and on income from continuing operations is provided in Note 13 of Notes to Consolidated Financial Statements.

Liquidity and Financial Flexibility

Funds provided by operations, or "cash flow", is the most important measure of the Company's performance, since it provides the financial resources to cover capital expenditures, debt service and the payment of dividends. All segments of the Company's operations have contributed to increased cash flow. Aided by increased crude oil and natural gas prices, favorable refinery margins and acquisitions, cash flow increased 47% in 1980 following a 45% increase in 1979 and a 22% increase in 1978.

The Company's basic strategy of growth has been to reinvest cash flow into operations, borrow to finance acquisitions and raise new equity when needed to restore flexibility to the balance sheet. Major acquisitions have been funded primarily by debt — $210 million in 1980 for the Vickers acquisition and $65 million in 1977-78 for the Apco acquisition. Major sources of equity financing came from the sale of 2.5 million Common shares in 1978 yielding $22 million and the sale of 2.8 million Preferred shares in 1979 yielding $117 million. The $10 warrants issued in 1976 expired at December 31, 1980 and approximately 1.6 million were exercised before that date adding $16 million of new equity.

Although a large amount of debt was raised in 1980 to finance acquisitions, the Company still has substantial borrowing capacity. Lines of credit amounting to $92.5 million were available at December 31, 1980. Oil and gas reserves which are not pledged could be used to secure a substantial amount of new debt. Capital expenditures in 1981 will be about $100 million and are expected to be funded by cash flow.

Consolidated Balance Sheet

Total Petroleum (North America) Ltd. and Subsidiaries
(Thousands of U.S. dollars)

	December 31	1980	1979
Assets	Cash	$ 22,930	$ 9,483
	Short-term investments	34,696	5,140
	Accounts and notes receivable	298,148	127,010
	Inventories of purchased crude oil and products	136,343	57,068
	Inventories of merchandise, materials and supplies	13,503	7,523
	Prepaid expenses and other	7,555	5,941
	Total current assets	513,175	212,165
	Short-term investments held for acquisitions	—	94,500
	Long-term receivables and other assets	4,932	5,081
	Property, plant and equipment, net ("full cost" method)	636,910	312,516
		$1,155,017	$624,262
Liabilities	Accounts and notes payable (Note 10)	$ 353,033	$150,982
	Accrued taxes	72,127	14,898
	Other accrued liabilities	21,123	10,495
	Current portion of long-term debt	5,375	20,360
	Total current liabilities	451,658	196,735
	Long-term debt	278,060	68,542
Deferred Credit	Deferred income tax provision	67,420	52,420
Shareholders' Equity	Capital Stock		
	Preferred shares	116,602	116,665
	Common shares	30,675	14,328
	Contributed surplus	92,213	92,213
	Retained earnings	118,389	83,359
		357,879	306,565
		$1,155,017	$624,262

See Notes to Consolidated Financial Statements

Approved on Behalf of the Board:

L. J. Richards

Director

Director

Consolidated Statement of Changes in Financial Position

Total Petroleum (North America) Ltd. and Subsidiaries
(Thousands of U.S. dollars)

		1980	1979	1978	1977	1976
Funds Provided by Operations	Net income	**$ 47,749**	$ 29,871	$ 14,416	$ 12,964	$ 8,846
	Income charges not affecting working capital in the year:					
	Depreciation and depletion	**47,932**	31,358	30,063	21,693	17,717
	Deferred income taxes and other	**15,000**	13,800	7,100	7,700	6,390
		110,681	75,029	51,579	42,357	32,953
Funds Used For	Capital expenditures	**373,273**	54,262	98,271	50,848	82,652
	Short-term investments held for acquisitions	**—**	94,500	—	40,000	—
	Reduction of long-term borrowings	**7,020**	41,326	40,755	46,632	14,414
	Dividends	**12,719**	3,818	2,306	1,320	845
	Increase (decrease) in working capital	**46,087**	438	499	5,889	(10,504)
	Other	**(149)**	3,854	1,773	321	(605)
		438,950	198,198	143,604	145,010	86,802
Deficit		**$328,269**	$123,169	$ 92,025	$102,653	$ 53,849
Deficit Financed By	Property sales	**$ 947**	$ 6,133	$ 2,576	$ 2,415	$ 564
	Additional long-term borrowings	**216,538**	—	26,340	100,009	50,948
	Liquidation of short-term investments	**94,500**	—	40,000	—	—
	Issuance of equity securities, net of conversions	**16,284**	117,036	23,109	229	2,337
		$328,269	$123,169	$ 92,025	$102,653	$ 53,849
Increase (Decrease) in Working Capital	Cash and short-term investments	**$ 43,003**	$ 4,450	$ (6,385)	$ 7,223	$ (8,807)
	Accounts and notes receivable	**171,138**	64,528	34,402	4,830	6,789
	Inventories	**85,255**	479	41,975	2,833	(1,182)
	Prepaid expenses and other	**1,614**	2,126	(2,649)	501	4,257
	Accounts payable and other accrued liabilities	**(212,679)**	(62,223)	(57,881)	(6,317)	(6,382)
	Accrued taxes	**(57,229)**	(9,612)	(1,279)	345	(1,158)
	Current portion of long-term debt	**14,985**	690	(7,684)	(3,526)	(4,021)
		$ 46,087	$ 438	$ 499	$ 5,889	$ (10,504)

See Notes to Consolidated Financial Statements

Consolidated Statement of Income and Retained Earnings

Total Petroleum (North America) Ltd. and Subsidiaries
(Thousands of U.S. dollars, except per share amounts)

		1980	1979	1978	1977	1976
Revenue	Net sales of refined products	**$1,513,524**	$854,509	$522,832	$306,135	$264,472
	Net sales of crude oil and natural gas	**77,399**	53,294	44,533	41,146	31,374
	Other revenues and income	**13,614**	2,702	4,945	2,188	2,872
		1,604,537	910,505	572,310	349,469	298,718
Expenses	Purchased crude oil, products and merchandise (Note 10)	**1,281,885**	701,239	418,488	240,338	211,110
	Operating	**120,001**	81,671	61,243	36,801	29,670
	Marketing and administrative	**49,286**	30,902	27,078	22,281	19,778
	Depreciation and depletion	**47,932**	31,358	30,063	21,693	17,717
	Interest	**22,584**	13,564	14,322	7,392	6,207
	Income taxes	**35,100**	21,900	6,700	8,000	5,390
		1,556,788	880,634	557,894	336,505	289,872
Net Income		**47,749**	29,871	14,416	12,964	8,846
Retained Earnings	Retained earnings at beginning of year	**83,359**	57,306	45,196	33,552	25,551
	Dividends:					
	Preferred shares	**(6,880)**	—	(606)	(845)	(845)
	Common shares	**(5,839)**	(3,818)	(1,700)	(475)	—
	Retained earnings at end of year	**$ 118,389**	$ 83,359	$ 57,306	$ 45,196	$ 33,552

		1980	1979	1978	1977	1976
Per Share	Net income per share	**$2.30**	$1.82	$.98	$1.01	$.69
	Dividends per share:					
	Series A Preferred shares	—	—	$.525	$ .70	$.70
	Convertible Preferred shares (Can. $)	**$2.88**	—	—	—	—
	Common shares (Can. $)	**$ .44**	$ .29	$.15	$ .05	—

See Notes to Consolidated Financial Statements

Statement of Information by Industry Segment and Geographic Area

Total Petroleum (North America) Ltd. and Subsidiaries
(Thousands of U.S. dollars)

		1980	1979	1978	1977	1976
Revenue	Exploration and production					
	Canada	**$ 28,028**	$ 23,426	$ 18,494	$ 16,507	$ 13,956
	U.S.	**49,994**	30,730	26,285	25,023	17,669
	Refining and marketing — U.S.	**1,517,111**	856,889	524,739	306,698	265,742
	Unallocated	**9,404**	(540)	2,792	1,241	1,351
		$1,604,537	$910,505	$572,310	$349,469	$298,718
Funds Provided by Operations	Exploration and production					
	Canada	**$ 23,972**	$ 20,115	$ 16,110	$ 14,289	$ 12,011
	U.S.	**38,366**	21,390	18,302	18,441	13,245
	Refining and marketing — U.S.	**85,956**	58,060	30,092	17,613	12,632
	Unallocated					
	Other income	**9,404**	2,459	2,792	1,241	1,351
	Interest expense	**(22,584)**	(13,564)	(14,322)	(7,392)	(6,207)
	Income taxes	**(20,100)**	(11,100)	400	(300)	1,000
	Administrative	**(4,333)**	(2,331)	(1,795)	(1,535)	(1,079)
		$ 110,681	$ 75,029	$ 51,579	$ 42,357	$ 32,953
Operating Profit	Exploration and production					
	Canada	**$ 16,819**	$ 13,128	$ 10,645	$ 10,319	$ 8,362
	U.S.	**11,801**	4,301	(138)	3,990	3,025
	Refining and marketing — U.S.	**71,742**	50,778	23,934	14,341	8,784
	Unallocated expenses, net	**(17,513)**	(16,436)	(13,325)	(7,686)	(5,935)
		$ 82,849	$51,771	$21,116	$20,964	$14,236
Capital Expenditures	Exploration and production					
	Canada	**$ 23,185**	$ 20,484	$ 18,700	$ 11,885	$ 9,384
	U.S.	**24,237**	16,629	23,540	15,870	18,800
	Refining and marketing — U.S.					
	Refining	**11,882**	12,650	4,144	11,140	3,912
	Supply and transportation	**3,264**	1,932	1,404	1,024	736
	Marketing	**1,997**	1,591	1,740	684	1,238
	Administrative	**2,301**	976	718	395	971
		66,866	54,262	50,246	40,998	35,041
	Acquisitions	**306,407**	—	48,025	9,850	47,611
		$ 373,273	$ 54,262	$ 98,271	$ 50,848	$ 82,652
Depreciation and Depletion Expense	Exploration and production					
	Canada	**$ 7,153**	$ 6,987	$ 5,465	$ 3,970	$ 3,649
	U.S.	**26,565**	17,089	18,440	14,451	10,220
	Refining and marketing — U.S.	**14,214**	7,282	6,158	3,272	3,848
		$ 47,932	$ 31,358	$ 30,063	$ 21,693	$ 17,717
Assets at December 31	Exploration and production					
	Canada	**$ 132,614**	$115,636	$105,339	$ 91,743	$ 75,203
	U.S.	**139,470**	97,383	96,933	93,141	92,133
	Refining and marketing — U.S.	**825,307**	302,120	228,109	105,248	87,601
	Unallocated	**57,626**	109,123	10,173	56,558	9,335
		$1,155,017	$624,262	$440,554	$346,690	$264,272

See Notes to Consolidated Financial Statements

Notes To Consolidated Financial Statements

1. Accounting Policies

The significant accounting policies followed by the Company and its subsidiaries are presented here to assist the reader in reviewing the financial information contained herein. The Company's accounting policies are based on generally accepted accounting principles in the United States. Any material differences between those principles and the principles recommended by the Canadian Institute of Chartered Accountants are disclosed in the financial statements or the notes thereto.

Principles of Consolidation
The consolidated financial statements include the accounts of all subsidiaries.

Business Segments (Classes of Business)
The Board of Directors has determined that the Company's operations can be divided into two business segments. Such determination is recorded in the minutes of a meeting of the Board on February 23, 1980. Exploration and Production includes the exploration for, and development and production of, petroleum and natural gas reserves. Refining and Marketing includes the refining of crude oil and the distribution and marketing of refined products. Other income (principally financial) and expenses incurred at the corporate level are not allocated to the segments. Unallocated assets are cash and short-term investments.

Foreign Currency Translation
The Company presents the consolidated financial statements in United States dollars because the majority of the transactions and the major portion of the working capital and long-term debt of the consolidated companies are in that currency. Canadian assets and liabilities representing cash and amounts owing to or by the Company are translated at the rate of exchange in effect at the end of the period. Other assets (such as inventories and property, plant and equipment) and deferred income taxes are translated at historical rates. Operating results for the period are translated at the monthly average rate of exchange during the year; depreciation and depletion included in operating results are translated at historical rates. Currency translation gains and losses, which are not material, are included in net income.

Short-term Investments
The amount of short-term investments, whether classified as a current or long-term asset in the Consolidated Balance Sheet, represents the cost of investment. The market value of such investments exceeded cost by approximately $20,000,000 at December 31, 1980.

Inventories
Inventories are valued at the lower of cost or net realizable value. Cost of inventories of crude oil and refined products is determined by the last-in, first-out method. Cost of inventories of merchandise, materials and supplies is determined by the first-in, first-out method with respect to merchandise and by the average cost method for materials and supplies. The replacement cost of inventories at December 31, 1980 and 1979 was approximately $265,000,000 and $143,000,000 respectively.

Property, Plant and Equipment
Property, plant and equipment is carried at cost.

The Company follows the "full cost" method of accounting for its exploration and production activities. All costs of exploring for and developing oil and gas reserves are capitalized and charged to operations over the life of estimated future production (proved reserves) on the unit-of-production method. Proceeds from disposals are applied against such cost.

Depreciation is provided using the straight-line method based on estimated useful lives of assets.

Income Taxes
The Company does not provide for taxes which would be payable upon transfer of undistributed earnings of subsidiaries since management believes that either such earnings will not be transferred in the foreseeable future or no tax expense would be incurred because of available credits or deductions. At December 31, 1980 undistributed earnings of subsidiaries amounted to $83,881,000.

Investment tax credits are applied as a reduction of income tax expense in the period realized.

Other
Excise taxes collected from customers are excluded from the Consolidated Statement of Income and Retained Earnings.

Sales of purchased crude oil are deducted from the related purchases in the Consolidated Statement of Income and Retained Earnings.

Pension plans cover substantially all of the Company's employees. Current cost and accruals for prior service costs (accrued over 30 years) are funded currently.

2. Acquisitions

At December 31, 1979, the Company held $94,500,000 of short-term investments specifically for the purpose of future acquisitions. The Board of Directors of the Company had authorized management to search for and evaluate potential investments through acquisition of shares or assets of other companies principally in the energy resources sectors of the economy. During 1980, the short-term investments were used to effect two significant acquisitions; purchase of certain producing properties of Traverse Corporation for $42 million and the purchase of all outstanding capital stock of Vickers Petroleum Corporation for $325 million.

On October 2, 1980, the Company acquired all of the outstanding capital stock of Vickers Petroleum Corporation, a wholly owned subsidiary of Esmark, Inc. Immediately upon acquisition, Vickers Petroleum Corporation was liquidated into a wholly owned subsidiary of the Company. The underlying assets acquired include a refinery in Oklahoma, related pipeline facilities and service station properties located in the United States mid-continent area. The cost of the acquired assets, as measured by payments to the seller plus liabilities assumed and certain income tax liabilities incurred upon liquidation of Vickers, were attributed to current assets based on fair value with the remainder being attributed to property, plant and equipment. This allocation resulted in working capital at the date of acquisition of approximately $60,000,000 and cost of properties aggregating $264,321,000. Financing for the acquisition was provided by proceeds from borrowings under revolving bank credits (see Note 4), liquidation of short-term investments and working capital. At December 31, 1980, the Company had paid Esmark approximately $20 million less than the total requested by Esmark. The Company believes that the amounts paid are the maximum payments required under the agreement and that any further payments or refunds upon resolution of the issues will not be significant.

The following table provides results of operations for the Company for the years ended December 31, 1980 and 1979 on a pro forma basis after giving effect to the acquisition of Vickers and assuming such acquisition had occurred at the beginning of the period. In the table, historical financial results of Vickers for periods prior to the acquisition, which do not necessarily reflect the results that would have resulted from operation of the assets by the Company or results that can be expected from future operations, are added to the Company's historical results. Further adjustment is made to reflect, retroactively, financing cost and depreciation expense, net of related tax benefits, commensurate with financing arrangements and costs incurred in the acquisition (in thousands of dollars except per share amount).

(unaudited)	1980	1979
Revenues	$2,664,135	$1,796,721
Net income	$ 26,907	$ 8,253
Net income per share	$ 1.22	$ 0.50

Pursuant to an agreement dated August 19, 1977, the Company acquired assets from Apco Oil Corporation as follows:

- producing petroleum and natural gas properties in western Canada.
- a refinery and certain related pipeline, terminal and shipping facilities located in the United States mid-continent area.
- inventories and accounts receivable related to the United States properties.

The purchase of the producing properties was completed on December 20, 1977 at a cost of approximately $9.8 million. In 1978 the Company filed notice of this acquisition with the Foreign Investment Review Agency (FIRA) in Canada. In July 1979 the federal government issued an

order refusing to allow the acquisition on the grounds that it was not likely to be of significant benefit to Canada. The Company then filed a second notice with FIRA for approval of its acquisition of such Canadian assets. In late 1980, following indications from FIRA that the 1979 disallowance of the acquisition would stand, the Company withdrew its second notice and began the process of disposing of these properties. The Company believes that no loss will be incurred in this disposal.

On April 1, 1978 the purchase of the United States assets was completed after receiving the required ruling from the Department of Energy. Because a more timely ruling from the Department of Energy was expected, the financing for the acquisition was partially completed in 1977. The proceeds received in advance of their need were placed in short-term investments and, because of the intended use of the monies, were classified as a noncurrent asset in the Consolidated Balance Sheet at December 31, 1977.

Since the closing date, the Company and Apco have been unable to agree upon the purchase price for the inventories and accounts receivable. The Company has also asserted claims against Apco based upon the allegations, among others, that Apco has breached certain covenants and warranties. The amounts at controversy in the litigation add to approximately $10 million, which amounts the Company withheld from payments to Apco. The Company has paid approximately $98.7 million, all in 1978, for the United States assets, this being the entire amount due unless the courts rule unfavorably. The payments have been allocated first to inventories and receivables with the remainder of $48.0 million attributed to the refinery and other facilities. Any additional payments that might be required upon settlement of the dispute will be applied as an increase in the cost of the refinery and other facilities.

3. Property, Plant and Equipment

Property, plant and equipment is as follows (in thousands):

	1980	1979
Exploration and production	$357,874	$268,702
Refining	249,147	93,291
Marketing	130,062	31,824
Supply and transportation	42,338	27,716
Other	16,661	4,563
	796,082	426,096
Accumulated depreciation and depletion	159,172	113,580
	$636,910	$312,516

4. Debt

The following summarizes the consolidated long-term debt (in thousands):

	1980	1979
Notes payable:		
Due 1981, interest at six months London Interbank Eurodollar Market rate plus 1%	$ —	$ 5,000
Due 1982, interest 8½%	20,000	20,000
Due 1983, interest 8⅝%	20,000	20,000
Revolving credits	210,000	—
Production payments	10,660	22,486
Guaranteed 11½% Sinking Fund Debentures due December 31, 1990 (subordinated)	10,625	14,092
Other secured debt at 5½% to 10½%	12,150	7,324
	283,435	88,902
Current maturities	5,375	20,360
	$278,060	$68,542

In connection with the acquisition of Vickers Petroleum Corporation in 1980, the Company entered into revolving credit agreements with ten banks. The agreements provide for maximum aggregate borrowings of $270,000,000 at rates based on domestic or Eurodollar short-term market rates. Prior to December 31, 1983 the Company may borrow any amount desired from time to time up to the maximum. Any borrowings outstanding on January 1, 1984 are payable in equal semi-annual installments beginning on June 30, 1984 with the final payment due on December 31, 1988.

The Guaranteed 11½% Sinking Fund Debentures are payable by a subsidiary and guaranteed as to payment of principal and interest (on a subordinated basis) by the Company. The sinking fund provisions require annual payments of $1,740,000 from December 1981 through December 1988 with the remaining balance due on December 31, 1990. In 1979 the Company elected to redeem

$1,740,000 of the debentures effective January 1, 1980. Because of this redemption and repurchases in market transactions, sinking fund payments may be omitted in 1981, 1982 and 1983. Payments of approximately $185,000 in 1984 and $1,740,000 in 1985 through 1990 will be required.

The purchaser of the production payment outstanding at December 31, 1980 receives 65% of the revenues net of royalties from specified properties. Payments are applied to interest at 0.85% above Canadian prime and to reduction of the primary sum. If the primary sum is not reduced by more than certain stated amounts, the revenue percentage may be increased, but the purchaser may look only to revenues from the specified properties for both interest and the return of the primary sum.

Interest expense on long-term borrowings was:

1980—$18,641,000	1978—$12,930,000	1976—$ 6,014,000
1979—$12,288,000	1977—$ 7,024,000	

Minimum annual maturities of long-term debt for the next five years are as follows:

1981—$ 5,375,000	1983—$24,096,000	1985—$44,893,000
1982—$25,394,000	1984—$43,127,000	

At December 31, 1980 the Company or its subsidiaries had unused commitments from various banks for future borrowings aggregating $92,500,000, of which $32,500,000 would be on a short-term basis. Borrowings under such agreements would be at the prime interest rate or at margins of ¼% to ⅜% over money market rates. Commitment fees on the unused available credits range from ¼% to ⅜%. Under terms of the commitment agreements, $32,500,000 will expire in 1981 and $60,000,000 in 1983.

5. Income Taxes

Income before income taxes and the provision for income tax expense included in the Consolidated Statement of Income and Retained Earnings are as follows (in thousands):

	1980	1979	1978	1977	1976
Income before income taxes:					
U.S.	$61,202	$42,230	$13,398	$12,255	$ 6,785
Canadian	21,647	9,541	7,718	8,709	7,451
	$82,849	$51,771	$21,116	$20,964	$14,236
Current tax provision payable (refundable):					
U.S.	$20,200	$ 3,850	$ 250	$ —	$ —
Canadian	3,400	(850)	(650)	300	(1,000)
Deferred tax provision:					
U.S.	5,600	13,700	4,450	5,015	2,630
Canadian	5,900	5,200	2,650	2,685	3,760
	$35,100	$21,900	$6,700	$8,000	$5,390

Substantially all of the Canadian deferred tax provision results from the deduction of exploration and development expenditures on various bases which generally have the effect of permitting such deduction to be made for tax purposes in advance of the related deduction from income for book purposes. Tax laws in the United States contain provisions which have a similar effect. The U.S. deferred tax provision consists of timing differences related to the following (in thousands):

	1980	1979	1978	1977	1976
Exploration and development costs	$ 1,400	$ 2,200	$ 750	$ 1,415	$ 4,430
Utilization of tax loss carryforward	—	—	2,100	3,900	(2,800)
Revenue recognition differences	(2,500)	7,300	1,600	—	—
Depreciation expense	6,800	1,900	2,000	—	400
Allocation of purchase price of acquired assets	—	—	(2,000)	—	—
Investment tax credits	1,100	3,900	(1,100)	(1,000)	(700)
Other	(1,200)	(1,600)	1,100	700	1,300
	$5,600	$13,700	$ 4,450	$ 5,015	$ 2,630

Investment tax credits are applied as a reduction of the tax expense, thereby reducing the expense to an amount below the statutory tax rate. Credits and special allowances in Canada similarly reduce taxes otherwise payable. Royalty and other payments to governments are not deductible for Canadian federal income tax purposes.

Income tax expense is at rates other than the statutory U.S. income tax rate as follows (in thousands):

	1980	1979	1978	1977	1976
Income before income taxes	$82,849	$51,771	$21,116	$20,964	$14,236
Statutory U.S. rate	46%	46%	48%	48%	48%
Tax provision at statutory rate	38,111	23,815	10,136	10,063	6,833
Differences:					
Canadian taxes at rates higher (lower) than U.S. rates	120	(40)	(1,306)	(393)	7
State income taxes and other	(106)	400	50	130	50
Investment and other tax credits	(2,225)	(1,475)	(1,380)	(1,000)	(700)
Amortization of additional tax basis on properties distributed as a dividend by a subsidiary	(800)	(800)	(800)	(800)	(800)
	$35,100	$21,900	$ 6,700	$ 8,000	$ 5,390

At December 31, 1980 the Company had the following approximate deductions and credits available to reduce Canadian tax payments which would otherwise be required in future years:

Property expenditures	$ 3,000,000
Development expenditures	$10,700,000
Capital cost allowance	$ 4,200,000
Depletion allowance	$20,900,000

Upon utilization, the benefits of these carryforwards will be credited to the deferred income tax provision in the balance sheet except for approximately $5,900,000 related to Canadian depletion which will be credited to income.

6. Capital Stock

At the Company's annual meeting on April 29, 1980, shareholders approved resolutions setting authorized capital consisting of 12,800,000 Preferred shares and 10,000,000 Second Preferred shares without nominal or par value, issuable in series, and an unlimited number of Common shares without nominal or par value. 2,800,000 of the authorized Preferred shares, 2,798,690 of which represent the Preferred shares outstanding at December 31, 1980, are designated as $2.88 Cumulative Redeemable Convertible Preferred shares ("Convertible Preferred shares").

Changes in issued capital stock and contributed surplus are as follows (in thousands of dollars):

	Preferred Shares		Common Shares		
	Number of Shares	Amount	Number of Shares	Amount	Contributed Surplus
Balance January 1, 1978	1,196,459	$ 23,929	10,459,001	$ 9,947	$49,945
Sales of Common shares, net of expenses	—	—	2,500,000	2,219	20,254
Conversion of Series A Preferred shares into Common shares	(1,158,473)	(23,169)	2,316,946	1,968	21,201
Redemption of shares	(37,986)	(760)	—	—	—
Exercise of stock options and warrants	—	—	125,006	110	526
Balance December 31, 1978	—	—	15,400,953	14,244	91,926
Sales of Convertible Preferred shares, net of expenses	2,800,000	116,665	—	—	—
Adjustments to 1978 Preferred share conversion	—	—	264	—	3
Exercise of stock options and warrants	—	—	42,611	84	284
Balance December 31, 1979	2,800,000	116,665	15,443,828	14,328	92,213
Exercise of stock options and warrants	—	—	1,639,545	16,292	—
Adjustments to 1979 sale of Convertible Preferred shares	—	(8)	—	—	—
Conversion of Convertible Preferred shares into Common shares	(1,310)	(55)	1,873	55	—
Balance December 31, 1980	2,798,690	$116,602	17,085,246	$30,675	$92,213

The holders of the Convertible Preferred shares are entitled to receive fixed cumulative preferential cash dividends, if and when declared by the Board of Directors, at an annual rate of $2.88 (Can.) per share payable quarterly beginning March 20, 1980. The Convertible Preferred shares are convertible into Common shares at any time at the option of the holder at a conversion rate of 1.43 Common shares for each Convertible Preferred share. These shares may be redeemed by the Company after December 20, 1981 (but only under certain conditions prior to December 20, 1983) at specified prices declining from a high of $52.40 (Can.) per share to a low of $50.00 (Can.) per share after December 20, 1989.

Warrants to purchase 1,588,445 Common shares at $10 (U.S.) per share were exercised in late 1980 prior to their December 31, 1980 expiration. Similar warrants to purchase 40,587 Common shares had not been exercised by that date. Holders of these warrants will receive one Common share for each 100 warrants held or a cash equivalent. Adjustments will be made in 1981 for warrants deemed exercised.

Options to purchase 64,800 of the Company's Common shares at prices ranging from $6.83 to $28.50 (Can.) were outstanding at December 31, 1980 pursuant to the 1975 Stock Option Plan for Employees. Holders of options may exercise at any time within five years of the date of grant, but only while they continue to be employees. No charges are made to income in connection with the option plan. Senior officers held 7,000 of the outstanding options.

The Board of Directors passed a resolution in 1980 extending the term of the 1975 Stock Option Plan to November 30, 1990 and increasing the shares authorized such that 551,000 shares would be available for granting of options. This resolution is subject to stockholder approval.

7. Net Income Per Share

The computation of net income per share in the Consolidated Statement of Income and Retained Earnings is based on the weighted average shares outstanding during the year. Average shares include outstanding Common shares, Common shares that would be issued assuming conversion of all Preferred shares and the incremental shares that would be issued assuming all dilutive options and warrants outstanding during the year were exercised at the beginning of the year and the proceeds were used to purchase treasury shares.

Under Canadian practice, basic net income per share is calculated based on the net income available to Common shares (net income less dividends on Preferred shares) and the weighted average number of Common shares outstanding. The calculation of fully diluted net income per share is based on net income increased by net earnings which would be realized from investment of proceeds received on exercise of warrants and options. The shares used in the calculation include the Common shares outstanding plus the shares reserved for conversion of Preferred shares and exercise of warrants and options. Net income per share pursuant to Canadian practice is as follows:

	1980	1979	1978	1977	1976
Basic	$2.63	$1.94	$1.07	$1.16	$ .77
Fully diluted	$2.32	$1.81	$ .94	$ .93	$ .70

8. Pension Plans

The Company and its subsidiaries have several separate pension plans covering substantially all of their employees. The total pension expense for all plans was: 1980—$1,635,000, 1979—$2,089,000, 1978—$1,945,000, 1977—$1,526,000, and 1976—$1,386,000, which includes amortization of past service costs over 30 years. Annually, the Company makes the maximum tax-deductible contribution to the plans.

A comparison of accumulated benefits and net assets for the Company's pension plans (excluding the Canadian plan) is presented below (in thousands of dollars):

	January 1 1980
Actuarial present value of accumulated plan benefits:	
Vested	$12,780
Non-vested	1,430
	$14,210
Net assets available for benefits	$20,850

The assumed rate of return used in determining the actuarial present value of vested and non-vested accumulated plan benefits is 7% per annum, compounded annually. Net assets are stated at market values.

9. Quarterly Results

Unaudited information for the individual quarters of 1980 and 1979 is presented on page 17.

10. Related Party Transactions

The Company purchases crude oil at market prices from Total International Limited, a wholly-owned subsidiary of Compagnie Française des Pétroles (CFP), a French corporation which owns approximately 50% of the voting shares of the Company. The aggregate of such purchases was $451,400,000 in 1980, $192,600,000 in 1979, $53,600,000 in 1978, $33,800,000 in 1977, and $51,900,000 in 1976. Accounts payable at December 31, 1980 include $36,900,000 (1979—$24,200,000) related to the purchases.

11. Federal Energy Regulation

The Company's U.S. operations are subject to regulations administered by the Department of Energy (DOE). Effective January 28, 1981, substantially all crude oil and refined petroleum products were exempted from price and allocation controls. Nevertheless, the Company continues to be subject to DOE audits and the possibility of alleged violations of the regulations as interpreted by the DOE for the control period.

On March 17, 1980, the Company received a Notice of Probable Violation (NOPV) concerning certain processing agreements. The NOPV does not state any monetary claim against the Company. On September 26, 1980, the Company received a NOPV alleging that the Company had improperly calculated allowable finished product selling prices. By way of a proposed Consent Order (the Order) signed by the Company on January 19, 1981, the Company believes that it has settled all civil claims and disputes with the DOE pursuant to this NOPV. The Order requires the Company to remit a $2 million payment to the DOE, and reduce future maximum allowable prices by $18 million. The Order does not include transactions related to crude oil or the preacquisition activities of Vickers Petroleum Corporation. The Company has provided for all losses anticipated under this Order.

An issue which is the subject of litigation between the DOE and certain other companies may result in retroactive refunds or increases in the prices of crude oil purchased in periods prior to decontrol. The future impact on the Company will depend on the outcome of the litigation and on the provisions to be established by the DOE in connection with implementation of decontrol.

The Company believes that the liabilities, if any, that it might incur upon the resolution of all unresolved issues will not be materially important in relation to the Company's financial position.

12. Exploration And Production Activities

Additional Financial Information

The information presented below provides additional details concerning the Company's oil and gas exploration and production activities. The capitalized cost at the end of the year provides detail of the gross cost of exploration and production properties. The cost of proved properties includes all costs for which evaluation has been completed. Unproved properties includes lease acquisition and the related carrying and exploration costs for properties not yet proved or abandoned plus the cost of wells drilling at the end of the year.

Property acquisition costs incurred in the year include the costs of purchases of proved properties in the U.S. in 1980 of $30,053,000. Exploration costs are those costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and carrying costs of undeveloped properties. Development includes costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. Production or lifting costs include severance taxes and costs incurred to operate and maintain wells and related equipment.

As indicated in Note 1, depletion is charged over the life of estimated future production on the unit-of-production method. Under this method the depletion rate per equivalent barrel is computed by dividing proved reserves into the accumulated undepleted cost of exploration and production properties. The rate per barrel is then multiplied by the equivalent barrels of sales during the year to determine the charge to expense. Natural gas reserves and sales are measured in cubic feet and then converted to equivalent barrels of crude oil based on relative energy content (approximately six thousand cubic feet of gas per equivalent barrel).

Net revenues from oil and gas production are revenues less royalties and production expenses. All of the net revenues are derived from the Company's proved developed reserves.

Amounts are in thousands except for depletion expense per equivalent barrel.

			Canada	U.S.	Total
Capitalized cost at December 31:	1980 —	Proved properties	$117,914	$174,618	$292,532
		Unproved properties	31,017	34,325	65,342
			$148,931	$208,943	$357,874
	1979 —	Proved properties	$ 96,129	$122,245	$218,374
		Unproved properties	29,617	20,711	50,328
			$125,746	$142,956	$268,702
Accumulated depletion at December 31:	1980		$ 24,311	$ 81,501	$105,812
	1979		$ 17,198	$ 54,996	$ 72,194
Costs incurred in the year for:	1980 —	Property acquisition	$ 3,387	$ 46,315	$ 49,702
		Exploration	14,028	10,919	24,947
		Development	5,770	9,089	14,859
		Total capitalized	$ 23,185	$ 66,323	$ 89,508
		Production (lifting)	$ 3,212	$ 9,689	$ 12,901
	1979 —	Property acquisition	$ 3,871	$ 2,930	$ 6,801
		Exploration	9,010	7,555	16,565
		Development	7,603	6,144	13,747
		Total capitalized	$ 20,484	$ 16,629	$ 37,113
		Production (lifting)	$ 2,568	$ 7,064	$ 9,632
Depletion expense charged:	1980		$ 7,153	$ 26,565	$ 33,718
	1979		$ 6,987	$ 17,089	$ 24,076
Depletion expense per equivalent barrel:	1980		$ 2.07	$ 7.56	
	1979		$ 1.90	$ 5.33	
Net revenues from oil and gas production:	1980		$ 24,193	$ 40,305	$ 64,498
	1979		$ 20,205	$ 23,457	$ 43,662

Reserve Quantities (unaudited)
The following table presents the estimated quantities of proved oil and gas reserves at December 31, 1978, 1979, and 1980 and details for changes in such quantities during 1979 and 1980. Natural gas liquids are combined with crude oil quantities. The reserve quantities are before deduction for royalties. Oil quantities are expressed in millions of barrels. Gas volumes are stated in billions of cubic feet.

	Canada		U.S.		Total	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved developed and undeveloped reserves —						
Reserves at December 31, 1978	26.71	213.94	7.24	62.07	33.95	276.01
Increase (decrease) in 1979 due to:						
Revisions of previous estimates	(.34)	(2.12)	.85	.84	.51	(1.28)
Extensions and discoveries	.76	12.05	.46	3.51	1.22	15.56
Production	(2.34)	(8.06)	(1.64)	(10.33)	(3.98)	(18.39)
Purchases of reserves in place	—	—	.11	3.00	.11	3.00
Reserves at December 31, 1979	24.79	215.81	7.02	59.09	31.81	274.90
Increase (decrease) in 1980 due to:						
Revisions of previous estimates	(.39)	1.26	.60	1.29	.21	2.55
Extensions and discoveries	.58	18.65	.34	5.30	.92	23.95
Production	(2.11)	(8.01)	(1.70)	(10.88)	(3.81)	(18.89)
Purchases of reserves in place	—	—	1.60	5.60	1.60	5.60
Reserves at December 31, 1980	22.87	227.71	7.86	60.40	30.73	288.11
Proved developed reserves included above at —						
December 31, 1978	26.71	213.94	6.88	61.94	33.59	275.88
December 31, 1979	24.79	215.81	6.71	58.97	31.50	274.78
December 31, 1980	22.87	227.71	7.43	60.07	30.30	287.78

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. As this definition indicates, the measurement of reserves is based on estimates. The estimates are based on subjective judgements and interpretations of insufficient information as to a variety of uncertainties, including those imposed by the natural environment underground and those resulting from governmental actions and market conditions. Because of these uncertainties, it is possible that the ultimate recovery of hydrocarbons from the proved reserves will be significantly different from the quantities reported herein. The Company believes that its estimates are based on reasonable judgements and interpretations of available information, but that they are inherently imprecise.

Future Net Revenues From Proved Reserves (unaudited)
Future net revenues from proved reserves at December 31, 1980 are estimated to be realized as follows (in millions):

	Canada	U.S.	Total
1981	$ 23.2	$ 40.7	$ 63.9
1982	20.7	32.9	53.6
1983	20.5	24.2	44.7
1984 and beyond	305.7	101.0	406.7
	$370.1	$198.8	$568.9

The amounts for estimated future net revenues from proved reserves are based on procedures specified by the Securities and Exchange Commission. In the calculations, prices and costs in effect at the end of 1980 were assumed to continue for all future periods except for price escalation provisions in sales contracts. Crude oil volumes were shifted to higher priced categories pursuant to the decontrol plan announced by the U.S. federal government in 1979. Deduction was made for the "windfall profits" tax related to such increased revenues. The decontrol of all oil prices effective January 28, 1981 does not significantly increase the 1981 future net revenues. Provision was made for estimated future development expenditures that will be required to produce the estimated reserves. No consideration was given to income taxes nor any possible reduction in "windfall profits" tax as a result of application of the net income limitation on "windfall profit".

Provisions of the Canadian National Energy Program announced in 1980 were ignored in determining future net revenues. The 8% Petroleum and Gas Revenue Tax levied on gross operating revenues less lifting costs has the effect of reducing total future net revenues from proved reserves in Canada approximately $50,400,000 before discount ($20,860,000 after discount). The net revenue amounts related to Canadian reserves were translated to U.S. dollars at the exchange rate in effect at the end of the year.

The present value of estimated future net revenues from proved reserves at December 31, 1980 and 1979 was (in millions):

	Canada	U.S.	Total
1980	$166	$138	$304
1979	$140	$103	$243

The present value amounts are based on the future net revenues estimated at the respective dates pursuant to procedures described above. The future net revenues were discounted to their present value at the 10% rate specified by the SEC. These assumptions are not intended to result, and will not result, in an amount representing the current market value of the reserves. Nor does the amount represent management's best estimate of the present value of the stream of cash flows that will be realized. The calculation procedure is designed to require consistency of value data among companies to the extent of projections of future economic conditions and discount factor.

Summary of Oil and Gas Activities (unaudited)
In 1978, "reserve recognition accounting (RRA)" was introduced by the SEC as an experimental accounting method to be developed as a replacement for the two general historical cost methods currently followed by oil and gas producing companies. The SEC recently announced the abandonment of RRA as a primary method of accounting because of substantial evidence indicating that estimates of oil and gas reserves lack the degree of reliability considered necessary for primary financial statements. The SEC, nonetheless, considers the information developed from the RRA method to be beneficial to an understanding of the exploration and production business and requires the presentation of the information outside of the primary financial statements. The Company continues to believe that supplemental disclosure of a "valuation procedure" reflecting the economic results of exploration and production activities can provide useful information.

The conventional financial statements measure operating profit as oil and gas sales revenues reduced by production expenses, depletion charges, and overhead and administrative expenses attributable to the activities. Under RRA the results of oil and gas activities before taxes (conceptually the equivalent of operating profit) include the change in present value of estimated future net revenues, thereby recognizing the economic significance of the discovery of reserves, the effects of changing prices on previously discovered reserves and accretion of value as cash flows are realized. Depletion charges are replaced by direct charges of evaluated costs against the results.

The following summarizes oil and gas activities on the basis of RRA. The funds flow column represents the actual costs incurred and actual net revenues realized in the year. These amounts are included in the table under "Additional Financial Information" above. The amounts in the deferred cost column are required to adjust the funds flow to defer current year costs not yet evaluated and to charge off previously deferred costs which were evaluated in the year. The amounts under net present value of proved reserves are calculated under procedures prescribed by the SEC and as described under "Future Net Revenues from Proved Reserves" above. The net present value amounts for additions to estimated proved reserves and revisions are based on future revenues before deduction of estimated future development and production costs. The interest factor represents the increase in value caused by accretion of discount and is calculated on estimated future revenues net of future development and production costs.

Summary of Oil and Gas Activities on the Basis of Reserve Recognition Accounting (unaudited)

Year ended December 31, 1980 (in thousands)

	Funds Flow	Deferred Costs	Net Present Value of Proved Reserves	Results of Oil and Gas Activities
Additions to estimated proved reserves:				
Discoveries and extensions			$ 27,380	$ 27,380
Revisions to estimates of reserves proved in prior years:				
Changes in prices			56,199	56,199
Other (i)			1,108	1,108
Interest factor			28,711	28,711
			113,398	113,398
Costs incurred/evaluated:				
Property acquisition (excluding purchases of proved reserves)	$(19,649)	$14,664	—	(4,985)
Exploration	(24,947)	(30)	—	(24,977)
Development	(14,859)	2,065	—	(12,794)
Present value of estimated future development and production costs related to —				
1980 discoveries and extensions	—	—	(4,765)	(4,765)
Changes in prior year estimates	—	—	(6,961)	(6,961)
Net revenues from sales of oil and gas	64,498	—	(64,498)	—
Overhead and administrative expenses	(2,161)	—	—	(2,161)
Purchases of proved reserves	(30,053)	5,217	23,216	(1,620)
Subtotal	(27,171)	21,916	60,390	55,135
Provision for income taxes	4,900(iii)			28,900(iv)
Net change or amount	$(32,071)			$26,235
Balance, beginning of year		20,687	242,767	
Balance, end of year		$42,603	$303,157	

(i) Other revisions include changes to estimates of reserve quantities and timing of production and changes in the translation rate for Canadian reserves.

(ii) Costs incurred to purchase proved reserves plus related development costs.

(iii) Based on income realized and deductions and credits allowable in the year and assuming no limitation on their utilization. No provision is made for taxes which may become payable in the future.

(iv) In addition to the current taxes in (iii), includes the taxes which may become payable in future years (calculated at tax rates in effect at the end of the year) as the present value amounts are realized as funds flow, less the amount similarly calculated as of the beginning of the year.

Summary of Oil and Gas Activities on the Basis of Reserve Recognition Accounting (unaudited)

Year ended December 31, 1979 (in thousands)

	Funds Flow	Deferred Costs	Net Present Value of Proved Reserves	Results of Oil and Gas Activities
Additions to estimated proved reserves:				
Discoveries and extensions			$ 21,629	$ 21,629
Revisions to estimates of reserves proved in prior years:				
Changes in prices			54,042	54,042
Other (i)			4,962	4,962
Interest factor			22,075	22,075
			102,708	102,708
Costs incurred/evaluated:				
Property acquisition (excluding purchases of proved reserves)	$ (4,742)	$ (426)	—	(5,168)
Exploration	(16,565)	722	—	(15,843)
Development	(13,393)	—	—	(13,393)
Present value of estimated future development and production costs related to—				
1979 discoveries and extensions	—	—	(3,778)	(3,778)
Changes in prior year estimates	—	—	(21,311)	(21,311)
Net revenues from sales of oil and gas	43,662	—	(43,662)	—
Overhead and administrative expenses	(2,157)	—	—	(2,157)
Purchases of proved reserves	(2,413)(ii)	(1,922)	4,688	353
Subtotal	4,392	(1,626)	38,645	41,411
Provision for income taxes	(500)(iii)			19,500(iv)
Net change or amount	$ 4,892			$ 21,911
Balance, beginning of year		22,313	204,122	
Balance, end of year		$ 20,687	$242,767	

(i) Other revisions include changes to estimates of reserve quantities and timing of production and changes in the translation rate for Canadian reserves.

(ii) Costs incurred to purchase proved reserves plus related development costs.

(iii) Based on income realized and deductions and credits allowable in the year and assuming no limitation on their utilization. No provision is made for taxes which may become payable in the future.

(iv) In addition to the current taxes in (iii), includes the taxes which may become payable in future years (calculated at tax rates in effect at the end of the year) as the present value amounts are realized as funds flow, less the amount similarly calculated as of the beginning of the year.

13. Changing Prices (unaudited)

The financial statements included in this report are prepared on the basis of historical costs. The conventional accounting model reports the actual number of dollars received or expended without regard to changes in the purchasing power of the currency or changes in the cost of goods consumed. Depreciation and depletion charges are deducted from revenues in the calculation of net income even though the dollars expended to acquire properties in prior years had a different value, in terms of general purchasing power, than the value of revenues received in the current year. This mixing of transactions from various periods in which the dollars have differing values distorts the conventional measures of financial performance.

The accompanying schedules present the estimated effects of changing prices on certain financial information. Prices of specific goods and services change for many reasons in addition to the changes caused by the general decline in the value of the dollar. Any attempt to reflect the effects of changing prices on financial information involves the use of assumptions, approximations and estimates. Therefore, the resulting information should be regarded as an estimate of the effect of inflation, not a precise measure.

The constant dollar data adjusts the historical cost financial information to dollars having common units of measurement by use of an index which measures inflation. This price index, the Consumer Price Index for All Urban Consumers, measures the changes in the purchasing power of the dollar as such changes affect U.S. consumers as a group. The results of the approach do not purport to represent appraised value, replacement cost or any other measure of the current value of the underlying assets. The historical information was translated into average 1980 dollars.

The current cost disclosure measures the impact of changes in specific prices of property, plant and equipment, inventories, depreciation and depletion and purchases. The current cost of exploration and production assets was measured by applying an index based on the industry's average cost of drilling and equipping wells. The results are approximations of the amounts that would be required had past drilling and development occurred at today's prices. The remaining property, plant and equipment amounts were measured based upon current appraisals of fair market values. The amounts for depreciation and depletion are similarly adjusted. In computing depreciation and depletion, estimated lives and computational methods remained unchanged. The current cost of inventory was primarily determined from current market prices. The cost of purchased crude oil, products and merchandise did not change from historical amounts as inventories and purchases are accounted for under the LIFO method of inventory valuation in the historical financial statements. The LIFO method charges the most recent purchases to operations and, as a result, such charges approximate current cost. Amounts reported in the current cost column are also expressed in average 1980 dollars.

Statement of Financial Accounting Standards No. 33 requires that income tax expense not be adjusted for the effects of changes in purchasing power. This results in effective tax rates of 54.5% under constant dollar and 77.5% under current cost rather than the 42.4% historical cost rate. This failure to adjust the income tax expense conforms with the realities of current tax laws under which the governments realize higher revenues by taxing income which results from inflation.

While not adjusting income, the calculated gain from translation of net monetary liabilities and assets is presented. During an inflationary period, monetary assets, such as cash and receivables, lose purchasing power because they purchase fewer goods and services for consumption. The opposite is true for monetary liabilities, such as accounts and notes payable, since dollars having lesser purchasing power are used to satisfy the obligations. Most of the Company's assets other than inventory and property, plant and equipment are monetary, while the majority of the liabilities are also monetary. At the end of 1978, 1979 and 1980, the Company was in a net monetary liability position which resulted in purchasing power gains for both 1979 and 1980.

The constant dollar and current cost data presented here are only the initial step in developing meaningful financial information for an enterprise operating in an economy experiencing significant inflation. This supplementary disclosure is presented for the purpose of providing a basis for studying the usefulness of this type of information.

Five-Year Comparison of Selected Supplementary
Financial Data Adjusted for Changing Prices
(in thousands of average 1980 dollars)

	1980	1979	1978	1977	1976
Revenue	$1,604,537	$1,033,637	$722,856	$475,201	$432,396
Income from continuing operations (i):					
Constant dollar	$ 29,346	$ 22,522	—	—	—
Current cost	$ 10,210	$ 7,352	—	—	—
Income from continuing operations per Common share (i):					
Constant dollar	$ 1.34	$ 1.37	—	—	—
Current cost	$ .20	$ .45	—	—	—
Net assets at year-end (i):					
Constant dollar	$ 535,793	$ 472,712	—	—	—
Current cost	$ 759,319	$ 598,303	—	—	—
Gain from decline in purchasing power of net amounts owed (i)	$ 19,460	$ 25,736	—	—	—
Cash dividends declared per Common share	$ 0.37	$ 0.28	$ 0.17	$ 0.06	—
Market price per Common share at year-end	$ 21.61	$ 26.19	$ 18.40	$ 13.76	$ 10.44
Average consumer price index	246.80	217.40	195.40	181.50	170.50

(i) Information for years 1976 through 1978 has not been calculated.

Statement of Income from Continuing Operations Adjusted for Changing Prices
For the Year Ended December 31, 1980 (in thousands)

	As Reported in the Primary Statements	Adjusted for General Inflation (Constant Dollar)	Adjusted for Changes in Specific Prices (Current Cost)
Revenue	$1,604,537	$1,604,537	$1,604,537
Expenses:			
Purchased crude oil, products and merchandise	1,281,885	1,286,128	1,281,885
Operating	120,001	120,001	120,001
Marketing and administrative	49,286	49,286	49,286
Depreciation and depletion	47,932	62,092	85,471
Interest	22,584	22,584	22,584
Income taxes	35,100	35,100	35,100
	1,556,788	1,575,191	1,594,327
Income from continuing operations	$ 47,749	$ 29,346	$ 10,210
Net income per share	$ 2.30	$ 1.34	$ .20
Increase in current cost valuation of inventory and property, plant and equipment held during the year			$ 103,044
Effect of increase in general price level			88,868
Excess of increase in specific prices over increase in general price level			$ 14,176
Current cost at December 31, 1980:			
Inventory			$ 264,832
Property, plant and equipment, net			$ 959,053

Report Of Management

The financial statements and all information in this report are the responsibility of management. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances and, therefore, include amounts that are based on informed judgements and management's estimates. Other financial information in the report is consistent with that in the financial statements.

Management depends upon the Company's system of internal controls in meeting its responsibilities for reliable financial statements. This system provides reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. There are limits inherent in all systems of internal accounting control based on the recognition that the cost of such system should not exceed the benefits to be derived. The Company believes its system provides this appropriate balance.

The Company's independent accountants, Price Waterhouse & Co., have examined the financial statements as described in their report included herein. Their role is to render an independent professional opinion on management's financial statements to the extent required by generally accepted auditing standards.

The Audit Committee of the Board of Directors, which includes a majority of directors who are not employees of the Company, is responsible for reviewing the accounting principles and practices employed by the Company and reviewing the Company's annual financial statements prior to their issuance. The Audit Committee meets periodically with the independent accountants and management to review the work of each and ensure that each is properly discharging its responsibilities. The independent accountants are entitled to call a meeting of the Committee and are invited to discuss any matters they deem appropriate, with or without management being present.

Report Of Independent Accountants

To the Shareholders of
Total Petroleum (North America) Ltd.

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income and retained earnings and of changes in financial position present fairly the financial position of Total Petroleum (North America) Ltd. and its subsidiaries at December 31, 1980 and 1979, and the results of their operations and the changes in their financial position for each of the five years in the period ended December 31, 1980, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

PRICE WATERHOUSE & CO.

Detroit, Michigan
February 13, 1981

Pierre Capoulade

Martin E. Citrin

Louis Deny

Philippe Dunoyer

Joseph-Camille Genton

Pierre Germes

Alexander D. Hamilton

Vernon L. Horte

Linden J. Richards

David L. Torrey

William G. Tucker

Paul H. Gutknecht

Kenneth R. Buckler

Robert R. Dean

John E. Fawke

Gilbert M. Kiggins

Philippe Magnier

Robert A. Wall

Directors and Officers

Directors

Pierre Capoulade
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Martin E. Citrin
Partner, J. A. Citrin Sons Co.,
Birmingham, Michigan

Louis Deny
Executive Vice President and Deputy Chairman,
Compagnie Française des Pétroles,
Paris, France

Philippe Dunoyer
President and Chief Executive Officer,
Alma, Michigan

Joseph-Camille Genton
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Pierre Germes
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Alexander D. Hamilton
President and Chief Executive Officer,
Domtar Inc.,
Montreal, Quebec

Vernon L. Horte
President, V. L. Horte Associates Limited,
Calgary, Alberta

Linden J. Richards
Oil and Gas Consultant,
Tucson, Arizona

David L. Torrey
Vice Chairman and Director,
Pitfield Mackay Ross Limited,
Montreal, Quebec

William G. Tucker
Barrister and Solicitor,
Victoria, British Columbia

Principal Officers

Linden J. Richards
Chairman of the Board,
Tucson, Arizona

Philippe Dunoyer
President and Chief Executive Officer,
Alma, Michigan

Paul H. Gutknecht
Executive Vice President-Finance,
Alma, Michigan

Kenneth R. Buckler
Vice President-Administration,
Alma, Michigan

Robert R. Dean
Vice President-Manufacturing,
Supply and Transportation,
Alma, Michigan

John E. Fawke
Vice President-Marketing,
Romulus, Michigan

Gilbert M. Kiggins
Vice President,
New York, New York

Philippe Magnier
Vice President-Exploration and Production,
Houston, Texas

Robert A. Wall
Vice President, Secretary and
General Manager-Canadian Division,
Calgary, Alberta

William F. Kellock
Vice President Operations-
Canadian Division,
Calgary, Alberta

Donald F. West
Vice President Exploration-
Canadian Division,
Calgary, Alberta

Richard E. Dana
Treasurer,
Alma, Michigan

Ross S. Marzolf
Controller,
Alma, Michigan

John B. O'Brian
Vice President-Personnel and
Industrial Relations of
Total Petroleum, Inc.,
Alma, Michigan

Corporate Information

Registrars
National Trust Company, Limited
Calgary, Regina, Winnipeg,
Toronto, Vancouver and
Montreal, Canada

Morgan Guaranty Trust Company
of New York
New York, New York

Transfer Agents
National Trust Company, Limited
Calgary, Regina, Winnipeg,
Toronto, Vancouver and
Montreal, Canada

Morgan Guaranty Trust Company
of New York
New York, New York

Auditors
Price Waterhouse & Co.

Exchange Listings
Toronto Stock Exchange
Montreal Stock Exchange
American Stock Exchange
Pacific Stock Exchange

Form 10-K
Copies of the Company's annual report to the Securities and Exchange Commission on Form 10-K are available without charge upon request to the Company at East Superior Street, Alma, Michigan 48801, U.S.A.

Annual Meeting
Shareholders are cordially invited to attend TOTAL's Annual Meeting to be held this year at the Harbour Castle Hotel, One Harbour Square, Toronto, Ontario on Wednesday, April 29, 1981 at 10:30 a.m.

TOTAL